PB ASSOCIATES

POWERLINK REVENUE RESET

Review of Powerlink’s Supplementary Submission

Prepared for

AUSTRALIAN ENERGY REGULATOR

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EXECUTIVE SUMMARY

Background

The Australian Energy Regulator (AER), in accordance with its responsibilities under the National Electricity Rules, is determining the maximum allowed revenue for the prescribed transmission services to be provided by Powerlink Queensland (Powerlink) for the next regulatory period, which extends from 1 July 2007 to 30 June 2012.

On 15 December 2006, Powerlink submitted a supplementary revenue proposal, which increased the maximum allowed revenue that it had originally proposed. In submitting the supplementary revenue proposal, Powerlink stated that new and relevant information had emerged since it submitted its original revenue proposal and that the new information required revisions to its ex-ante capital expenditure requirement. The supplementary revenue proposal also contained consequential adjustments to operating expenditure allowances.

PB Associates has been engaged to review Powerlink's supplementary revenue proposal, and specifically whether:

- the additional forecast capex sought by Powerlink based on revised cost estimates for assets under construction and projects that commenced in the next regulatory period is reasonable and efficient;
- the additional forecast capex sought by Powerlink based on its revised probability of PNG gas generation is reasonable and efficient; and
- the additional forecast capex sought by Powerlink, based on its updated 2006 demand forecasts, is reasonable and efficient.

This report presents the results of PB Associates review.

Assets Under Construction

In its supplementary revenue proposal Powerlink submitted that the forecast capex in the next regulatory period should be increased by a total of $155.58 million (real 06/07) to reflect current project costs. The forecasts in its original revenue application were based on October 2005 costs for substation projects and February 2006 costs for transmission lines projects.

We reviewed the methodologies used by Powerlink to re-estimate the costs of projects under construction and found them to be reasonable and auditable. In particular we reviewed in detail the cost increases associated with four projects. The project cost increases generally arise from the current volatility in the cost of raw materials including, copper, aluminium and steel and the tight market for skilled labour, which is a consequence of the current mining boom in Australia, particularly Western Australia and Queensland.

We therefore consider that the increase in the forecast expenditure during the next regulatory period on projects that are currently under construction, as estimated by Powerlink, to be reasonable and recommend that it be accepted, subject to a minor reduction to the expenditure for one project.

Projects Commencing in the Next Regulatory Period

In its supplementary revenue proposal, Powerlink further submitted that the revised estimates of project costs as of June 2006 also be applied to projects for which construction would commence during the next regulatory period. It estimated that this would cause a further increase of $125.52 million (real 06/07) in the forecast capex for the next regulatory period.

In our view the evidence suggests that the current high material and labour costs will not be sustained through to the end of the next regulatory period. Materials prices appear to have peaked and are now generally lower than the highs seen in recent months. Current prices for futures contracts also indicate that suppliers expect prices to fall even further.

In addition, transmission and distribution network service providers are being proactive in addressing the current tight labour market. Service providers throughout Australia have substantially increased their apprentice intakes and we expect this to significantly increase the supply of skilled labour in the medium term. In addition, mining companies and contractors, who have traditionally recruited only from within Australia, are now recruiting skilled foreign workers on "457 visas" and this has the potential to make an impact in an even shorter time frame.

We therefore consider that the current high project costs are only temporary and that the market for both labour and materials will soon stabilise at more sustainable levels. On this basis we do not see any reason for the forecast costs of projects to be commenced in the next regulatory period to be increased over and above the costs estimated in Powerlink's original revenue application.

Papua New Guinea (PNG) Gas Pipeline Project

In its original revenue proposal, Powerlink assumed a likelihood of 50% for the market development scenario associated with generation from the PNG gas pipeline project proceeding prior to July 2010. In its supplementary revenue proposal, it concluded that due to reported significant increases in costs, the delayed history of the project, and AGLs decision to withdraw from the engineering and design activities, the theme set should be assigned a zero percent probability for the coming regulatory period. Powerlink proposed that the forecast capex in the next regulatory period should be increased by a total of $56.8 million (real 06/07) to reflect the reduced likelihood of generation from the PNG gas pipeline project proceeding.

Given the recent announcement by Oil Search Limited and the other PNG gas pipeline project partners to suspend work on the pipeline project to Australia, we concur with Powerlink that the PNG gas theme set should be set to zero percent probability when considering its future capex forecasts. However, we consider the final probabilities used in the probabilistic model by Powerlink should be slightly modified. This adjustment results in a reduction in the proposed increase in the forecast capex from $56.8 million to $46.8 million (real 06/07). Our recommendation was informed through a detailed review of the impact of the changed probability on one project.

Impact of Updated Demand Forecasts on Augmentations

Powerlink's original revenue proposal relied on demand forecasts as published in its Annual Planning report 2005. In its supplementary revenue proposal, Powerlink stated that it believed that the 2006 demand forecasts, published after its original revenue proposal was submitted, should be taken into account in the final decision.

It identified that the 2006 demand forecasts advance the timing of augmentations of the Queensland transmission network, particularly in south east Queensland. To account for this Powerlink proposed an increase in its forecast capex of $129 million (real 06/07).

We have not been asked to review the accuracy, validity or reasonableness of these increases in forecast demand and, for the purposes of this review, have assumed them to be reasonable. However, based on the size of the increased demand forecasts included in Powerlink's APR 2006, we have concluded that there is a need to increase Powerlink's forecast of capex in the coming regulatory period. Powerlink adopted a rigorous and systematic, but time constrained, review of the impacts of the increased demand forecasts on its revenue requirement involving the identification of 40 new transmission development plans for five key load centres in Queensland. The review was based on a fundamentally consistent approach to that used to develop its original revenue application.

However, from our detailed review of the processes and outcomes of Powerlink's assessment, including a comprehensive review of three projects, we recommend its forecast increase in capex over the next regulatory period be moderated. In particular, we consider that the development of the Halys-Blackwall 500 kV lines operating at 275 kV should be advanced by one year in critical scenarios, rather than three years, in conjunction with the advancement of the South Pine Static VAr Compensator project. This key adjustment, along with other minor changes reduces Powerlink's forecast capex increase as a result of the revised demand growth forecast from $129.0 million to $84.1 million (real 06/07).

1. INTRODUCTION

In this section we set out the background to this review, the objectives of the review and the scope of our engagement. We also include a description of the PB approach to the project.

1.1 BACKGROUND TO THE REVIEW

The Australian Energy Regulator (AER), in accordance with its responsibilities under the National Electricity Rules, is determining the maximum allowed revenue for the prescribed transmission services to be provided by Powerlink Queensland (Powerlink) for the next regulatory period, which extends from 1 July 2007 to 30 June 2012.

On 3 April 2006, Powerlink submitted a revenue proposal for the five-year regulatory period. The AER engaged PB to review Powerlink's proposed capital expenditure, historic capital expenditure, operational expenditure and service standards components of this proposal. The AERs draft decision on the maximum allowed revenue and PBs final consultancy report were publicly released on 22 December 2006.

On 15 December 2006, Powerlink submitted a supplementary revenue proposal, which increased maximum allowed revenue that it had initially proposed. In submitting the supplementary revenue proposal, Powerlink stated that new and relevant information had emerged since it submitted its initial proposal and that the new information required revisions to its ex ante capital expenditure requirement. The supplementary revenue proposal also contained consequential adjustments to operating expenditure allowances.

Powerlink's supplementary revenue proposal was based on:

- a review of projects in the Central Queensland – South Queensland grid section;
- revised capital cost estimates for assets under construction and capital projects in the next regulatory period;
- the revised probability of generation from PNG gas pipeline;
- the advancement in timing of projects based on the 2006 demand forecasts; and
- a requirement by NEMMCO to install high speed monitoring equipment.

1.2 OBJECTIVE AND SCOPE OF WORK

PB Associates has been engaged to review certain aspects of Powerlink's supplementary revenue proposal including whether:

- the additional forecast capex sought by Powerlink based on revised cost estimates for assets under construction and projects that commenced in the next regulatory period is reasonable and efficient;
- the additional forecast capex sought by Powerlink based on its 2006 demand forecasts is reasonable and efficient; and
- the additional forecast capex sought by Powerlink based on its revised probability of generation from the PNG gas pipeline project proceeding is reasonable and efficient.

PBs complete terms of reference are included in Appendix A.

1.3 PB APPROACH TO THE REVIEW

We visited Powerlink for two days in late January 2007 to collect information relevant to the review and also to discuss with Powerlink staff the analysis methodology used to compute the additional forecast expenditure contained in the supplementary revenue proposal and the assumptions that were made in determining the input assumptions to the analysis.

Following this visit we undertook our own analysis and prepared this report from our home office. Over this time we were in regular email contact with Powerlink and requested additional information as required. We found Powerlink very responsive to our requests and the information requested was invariably provided within a very short time frame. We would like to acknowledge their assistance throughout this process.

1.4 POWERLINK PROCESS FOR IMPLEMENTING ADJUSTMENTS

As a high level overview of Powerlink's supplementary revenue proposal, Table 1.1 provides a sequential[1] and quantified outline of the drivers and quantities of the capex adjustment sought. It does not include any recommendations contained in our previous report or the AERs Draft Determination, (except for the revised CQ-SQ capex that was identified by Powerlink).

Table 1.1: Adjustments to proposed capex ($ million, 06/07)

Driver	2007/08	2008/09	2009/10	2010/11	2011/12	Total	Progressive Total
Original proposal	546.31	543.02	456.10	466.49	437.32	2,449.24	
Revised CQ-SQ	(21.35)	(60.66)	5.99	33.42	1.57	(41.03)	2,408.21
Increased costs of projects under construction	88.01	61.77	6.11	(0.22)	(0.09)	155.58	2,563.79
Increased unit rates for future projects	10.37	24.97	30.40	32.71	27.06	125.52	2,689.31
PNG theme set	(0.25)	2.60	36.17	18.39	(0.13)	56.78	2,746.09
2006 load forecast	55.12	54.42	-57.27	50.33	26.40	129.00	2,875.09
NEMMCO HSM project[2]	0.43	1.28	0.64	-	-	2.35	2,877.44
Supplementary proposal	678.64	627.4	478.14	601.12	491.14	2,877.44	
Nett increase	132.33	84.38	22.04	134.63	53.82	428.20	
Nett increase %	24.2%	15.5%	4.8%	28.9%	12.3%	17.5%	

Source: PB Associates based on Powerlink Supplementary Submission.

1 The order of the adjustments is important to determine the impact of each driver, however the final increase will result irrespective of the order of individual adjustments.

2 The review of this expenditure is not covered by our terms of reference.

2. REVISED CAPITAL COST ESTIMATES

2.1 ASSETS UNDER CONSTRUCTION

Powerlink's original revenue proposal included a number of capital projects which incur expenditure across both the current (2002-07) and next (2007-12) regulatory periods. Its supplementary revenue proposal increased the capital cost estimates for some of these projects to reflect recent increases in input costs. Powerlink indicated that since estimates were prepared for approval of those projects in the second half of 2005, the cost of tower steel has increased by at least 15%, copper by 100% and aluminium for conductors by 40%. As a result the forecast expenditure during the next regulatory period to complete these projects under construction will increase by $156 million (real 2006/07) from its initial proposal.

The estimated $156 million increase has been calculated using a spreadsheet model that estimates the nominal expenditure, on an annual basis, required to complete each project where the total project cost estimate has increased and then deflates the nominal annual amounts to real 06/07 dollars. This spreadsheet model is attached to this report in Appendix C.

2.1.1 Review Terms of Reference – Assets under Construction

Under the terms of reference for this review, PB was asked to comment on whether the revised cost estimate is efficient. More specifically we were required to:

- identify the assets under construction where Powerlink has revised its cost estimates;
- describe and evaluate the evidence/material that Powerlink has relied upon when determining the increase in the proposed forecast capex allowance including contractor quotes, internal estimates and material prices;
- assess whether the process Powerlink has undertaken to review its cost estimates is robust, including whether the revised estimated cost is likely to reflect the efficient cost of the project; and
- where projects have been subject to cost revisions, comment on whether the project has been managed in accordance with Powerlink's corporate governance framework.

Furthermore the terms of reference required that the review of the revised cost estimates for assets under construction be informed by a detailed review of three projects. Each detailed project review should:

- identify the cost difference between the estimate in the initial revenue proposal and the estimate in the supplementary revenue proposal;
- analyse the impact of material price increases on the revised cost estimate;
- discuss the process Powerlink has undertaken to revise the estimated cost of the project including competitive tendering processes; and
- assess whether the revised cost estimate for the project is likely to be the efficient cost of the project in the current market conditions.

We were also required to assess whether the increase in Powerlink's proposed forecast capex allowance based on the revised cost estimates for assets under construction is efficient. If we do not agree with Powerlink's proposed increase in forecast capex, we must determine an alternative estimate.

2.1.2 Projects Under Construction

Powerlink has provided a detailed list of the 35 projects that have had their total cost revised in the supplementary revenue application and this list is included in Appendix C. The list identifies the projects where Powerlink revised its cost estimates, the method used by Powerlink for the revision and the reasons for the cost increases.

2.1.3 Powerlink's Review Process

Powerlink has used three methodologies to revise and quantify the total estimated costs for the projects currently under construction and these revised costs are used in its supplementary revenue proposal. The three methodologies are detailed below:

TCE (Target Cost Estimate)

Powerlink has entered into four-year period agreements with major contractors to provide construction services throughout its service area. These contractors generally work in separate areas of the state and do not compete for work in their respective areas. The three major line work contractors are John Holland, Downer and BBUGL and the substation construction contractors are Downer and Tenix. Whilst no guarantees of exclusivity or continued work are given to any of the contractors, John Holland is generally given work in the central region, BBUGL in the south east and Downer in the Townsville area. This approach is taken to minimise mobilisation and demobilisation costs on account of the high volumes of work available.

However, to ensure that costs remain competitive, Powerlink has put in place a number of procedures. These include a requirement that contractors provide open book access for all costs to Powerlink, the locking in of margins for the term of the contract, pre-qualification of steel suppliers, the use of agreed TCEs and the sharing of future unders and overs in a manner that encourages efficient project management. Powerlink compares the costs of the different contractors and has also used an independent quantity surveying consultant to compare costs with market averages.

Once a project is issued to a particular contractor, work commences to enable project variables such as latent conditions, site allowances and accommodation costs, and mobilisation costs to be determined. Once these variable costs are established Powerlink and the contractor agree on a TCE which then forms an integral component of the firm construction estimate. To this estimate Powerlink adds its supervision and commissioning costs and in most instances a contingency sum to cover unforseen changes in scope. The total of all these costs is the firm project cost estimate.

Where the TCE that has been agreed with the contractor for projects under construction is at variance with the detailed project estimate used in the original revenue application, the estimate to complete that project has been varied to reflect the TCE and the revised estimate has been included in the supplementary revenue proposal. This revised cost estimate does not include the contingency amount[3]. One project, CP.01087 was incorrectly included in the analysis with the contingency sum included and this issue is addressed within the report.

The revision of estimates using this process does not include the 2.6% estimation risk factor.

3 The contingency sum is included in the cost of each project as approved by the Powerlink Board. This avoids the need for management to seek Board approval for relatively small project cost overruns.

General percentage increase for line projects

Not all line projects currently under construction have advanced to the point where Powerlink and the construction contractor have agreed on a TCE. For these projects Powerlink has applied a general percentage increase to the forecast in its original revenue application. This increase is based on a re-estimate of the cost of a standard typical project. Powerlink determined the percentage cost increase resulting from this re-estimate and applied this same percentage increase to all lines projects currently under construction for which a TCE has still to be agreed. Powerlink used Project CP.1138 as its typical lines project and re-estimating the cost of this project resulted in an increase of 16% in total estimated costs.

All projects re-estimated using this process do not include contingency allowances nor the 2.6% estimation risk factor.

BPO (Base Planning Object) estimate update

Powerlink has revised the total estimates of substation and similar type projects, such as capacitor banks and static VAR compensators, by re-estimating the project using revised BPOs that were updated as of June 2006. In its original revenue proposal Powerlink used BPOs current at February 2006 to estimate line works and BPOs current as at October 2005 for substation works. We have included a detailed discussion of the revision of BPOs in Section 2.2 of this report.

In addition to using the revised BPOs to update total project estimates Powerlink has also incorporated tender prices for major equipment purchases if available, for example in the case of static VAR compensators.

All projects re-estimated using this process do not include any contingency allowances however six projects do include the 2.6% estimation risk factor. These projects were CP.00736, CP.01067, CPO.01243, CP.01265, CP.01285, and CP.01837.

2.1.4 Consistency in Approach

For projects currently under construction Powerlink has consistently applied the appropriate methodology described in Section 2.1.3 of this report to revise the total project estimate. This approach has resulted in a reasonable and auditable process to re-estimate the cost of projects under construction.

2.1.5 Detailed Project Reviews

In accordance with the terms of reference we carried out a detailed review of the revised total project estimates for three projects currently under construction.

The three projects we selected for review were:

- CP.1087 Bohle River to Townsville GT 132kV line
- CP.1294 Strathmore 275kV SVC
- CP.1134 South Pine 110kV Substation Refurbishment

We selected these three projects in order to review a range of projects including a lines project, a substation refurbishment project and a static VAR compensator project. However, Powerlink proposed an additional project for review in order to cover the full range of re-estimating methodologies used to review the cost estimates of assets under construction.

The additional project included by Powerlink was:

- CP.1138 SEQ Augmentation

As noted above, this project formed the basis for generally increasing the total estimates for all lines projects where the TCE had not already been agreed.

Table 2.1 displays the start date, the target completion date and the estimation methodology for each of the four projects.

Table 2.1: Start and Target Completion Date of Reviewed WIP Projects

Project No	Title	Start Date	Target Commissioning Date	Estimation Methodology
CP.1087	Bohle River to Townsville GT Line	June 2005	October 2007	TCE
CP.1294	Strathmore SVC	August 2005	October 2007	BPO
CP.1138	SEQ Augmentation	May 2005	October 2007	See Note 1
CP.1134	South Pine Substation Refurbishment	July 2006[2]	October 2009	BPO

Source: Powerlink

1. The cost estimate for this project was developed using BPOs but the project formed the basis for escalating the cost of those lines projects by 16% where no TCE had been agreed .

2 Project commenced with the replacement of some items of plant before summer 2006/07 for fault level reasons.

Whilst Powerlink has revised the total estimated cost of each project currently under construction where costs have increased, only that proportion of the cost which will be incurred in the next regulatory period has been included in the Supplementary Submission (Refer Appendix C).

Each review of the individual projects is discussed below:

2.1.5.1 CP.1087 - Bohle River to Townsville GT 132kV line

The total estimated cost for this project has been revised as a result of the target cost estimate (TCE) agreed with the contractor.

The Alan Sheriff substation to Townsville Gas Turbine (GT) Power Station 132 kV transmission line supplies the coastal communities north of Townsville and transfers power from the Townsville GT Power Station to the Townsville load centre. The existing line is 48 years old and approaching the end of its expected economic life. The section of line from the Alan Sheriff Substation to the Bohle River was rebuilt in 2003, whilst the Townsville Power Station was being converted to base load operation.

The remaining line from Bohle River to the Townsville GT Power Station, which comprises 14.5 km of double circuit steel tower line, has now reached a point where corrosion will accelerate rapidly unless corrective actions are put in place. Refurbishment or replacement was considered to be required within three to five years from the time of approval in 2005. This project was designed to address this issue.

The original project estimate approved by the Powerlink Board was $19.8 million which comprised the $18 million cost estimate plus a 10% contingency. The Boards re-approval was sought for $23.4 million, which comprises the new total estimate to complete of $21.9 million, which includes the contractors TCE, Powerlink's procurement, design and management costs and the contractors risk contingency. The amount of $23.4 million further includes a contingency of $1.5 million to cover unforseen changes in project scope. This is consistent with normal practice where the total estimate approved by the Board includes a contingency sum to cover construction uncertainties.

The Powerlink project team reviewing this project has indicated that the additional costs associated with this project are:

- $700,000 for additional upgrading of access tracks to allow for improved wet weather access to construction sites;
- upward pressure on the labour rates and living away from home allowances that were negotiated by the contractor to attract and retain labour;
- increases in material costs, particularly tower steel, conductor, OPWG and insulators;
- added costs for special foundations; and
- additional Powerlink design and management costs of $50,000.

The additional cost included in the supplementary revenue proposal to complete this project was $0.607 million (nominal) in 2008.

Comment

Changes to the original project design such as requirements for special foundation designs or access track upgrades are not unusual for this type of project and typically occur after the construction contractor starts on site and determines the specific soil type and access requirements at each tower location. Such costs are usually covered under the latent conditions section of the construction contract.

In the current industry environment where demand exceeds supply for resources such as skilled labour, which is primarily a consequence of the extremely high level of infrastructure construction activity associated with the mining industry; there is upward pressure on labour costs. It is therefore not surprising to see upward pressure on indirect labour costs such as site, accommodation and travel allowances.

As labour cost increases constitute a significant proportion of the increase in BPOs re-estimated as at June 2006, we requested additional information from Powerlink on the steps taken to ensure that the contractors were not exaggerating the impact of the current tight labour market when calculating the TCE for each project. Powerlink advised that it had engaged a quantity surveying firm, Currie & Brown, to advise of the appropriateness of the labour, plant and material costs currently being used by one contractor. We have reviewed an extract of the Currie & Brown report and noted that:

- the labour rates used were generally in line with current market rates with most being slightly below market; and
- the indirect labour costs including travelling allowance and living away from home allowances appeared reasonable.

In addition, 2006 has seen prices peak for nearly all metals including steel, copper and aluminium. Hence it would be reasonable to expect to see goods manufactured from these metals to also rise in price. We requested Powerlink to provide price information for power transformers and this data confirms that current prices are substantially higher than prices paid in 2005. For example cost increases experienced by Powerlink between 2005 and 2007 are as follows:

- 375 MVA, 275/110 kV auto transformers – 41%;
- 160 MVA 132/69/11 kV auto transformers – 38%; and
- 100 MVA, 132/69/11 kV auto transformers – 27%.

We therefore believe that Powerlink's revised cost estimate of $21.9 million for project CP.1087, which excludes the contingency allowance for prospective changes in scope, to be reasonable and, if the project is completed within the revised estimate, the costs to be efficient.

The Powerlink spreadsheet which was used to calculate the total impact of revising the estimates for asset currently under construction contained an error on the worksheet labelled 'Active Proj Changes – Total Nominal', wherein the revised estimate for project number CP.01087, Bohle River to Townsville GT 132kV Line, incorrectly included a contingency sum of $1.5 million. This was the only project to include a contingency sum in the forecast. In order to correct this error, the forecast expenditure for this project in 2008 should be reduced by $160,000 and the WIP provision should be reduced by $1.34 million.

2.1.5.2 CP.1294 - Strathmore 275kV SVC

As a contractors TCE was not available for this project, the estimate of the total cost to complete was revised upwards as a result of an increase in equipment costs the relevant BPOs following the June 2006 re-estimate.

This project involves the installation of a 275 kV Static VAR Compensator (SVC) with a nominal three phase swing range of 80 MVAr inductive to 260 MVAr capacitive at Powerlink's Strathmore substation in North Queensland.

The original cost estimate for the project was $38 million and Board approval was sought for $41.8 million, which included the capital works estimate plus a contingency allowance of 10%. The revised estimate to complete the project is now $47.35 million. This cost increase is due to:

- the price paid for the SVC, which was above the original estimate;
- an increase in the BPOs used to assemble the cost estimate; and
- the impact of latent conditions at the site.

Powerlink has advised that there are confidentiality issues associated with releasing the tender price of the SVC publicly. However it is well known that there are only a limited number of manufacturers currently capable of supplying this type of equipment and that there is currently a high demand for all electrical equipment. The SVC was sourced via a competitive tendering process and the lowest complying tender was accepted. Hence we accept that current market prices were paid for the equipment.

The change in the revised estimate resulting from the revision of the BPOs was provided by Powerlink and only comprised a small component of the overall cost increase. We have discussed the revision of the BPOs in detail in Section 2.2 below. The same revised BPOs were used in re-estimating this estimate as were used in forecasting future project costs.

Preparation of the site for the SVC foundations resulted in an increase of $3.1 million in the total project revised estimate. These costs related to the removal of rock at the site the extent of which was not evident to Powerlink when it initially estimated the cost of the project, even though rock was known to exist in the area. The remote location of the substation also contributed to the high foundation costs due to the need to move rock breaking equipment long distances to rectify the problem.

Nevertheless we asked Powerlink to provide a detailed explanation for the substantial increase in the civil works costs associated with the installation of the SVC foundation and the following information was provided.

The Strathmore SVC project was approved on a PIR[4] level estimate due to the timeframes required for the SVC project. A PIR level estimate is not a detailed bottom up estimate and is not normally used for project approval purposes. In this instance there was insufficient time to go through the normal bottom-up estimating process and obtain approval for implementation of the project by the required time. This was, at least in part, due to lengthening lead times for the supply of major equipment such as SVCs.

The investigation for the PIR included a desktop study of the site involving, a study of maps, contour charts, substation layouts (present and intended future) and site photographs. The position of the SVC platform was selected from site and contour maps, east of the existing and proposed future north-south 275 kV transmission lines. The civil group within Powerlink then calculated a typical cut and fill requirement using the contour maps for the PIR estimate. The estimated cost for civil works was $600,000 ($440,000 + $160,000).

One of the civil works contractors from Powerlink's panel was engaged to undertake the works at Strathmore. It is apparent that due to changing market conditions and the remote nature of the Strathmore substation site, the civil works contract was much higher than originally estimated during the PIR process. In addition to this, significant amounts of rock were encountered at the site which, while not entirely unexpected, were not anticipated to incur these cost levels.

Powerlink's civil group has advised that Strathmore is located between two hills and the location selected for the SVC was based on minimising the amount of civil works required. Due to the nature of the site and its known tendency for rock, the civil group advised that an alternative location for the SVC platform was unlikely to reduce the civil works costs.

The additional cost included in the supplementary revenue proposal to complete this project, CP.1294, is $4.477 million (nominal) in 2008.

Comment

We believe the additional cost associated with the purchase of the SVC, using a competitive tender process, is reasonable and is consistent with the higher costs currently being paid for power transformers, as discussed above.

In addition, the increased civil works costs for the construction of the SVC foundations seem reasonable under the circumstances. In our experience it is not always possible to accurately predict what will be found once excavation commences on site, sometimes even after on site test bores have been undertaken. The conditions experienced by Powerlink at this site are not uncommon, nor is the cost to rectify the situation. For example, cut and fill projects can sometimes uncover underground water courses which require diversion or require extensive retaining walls to stabilise the site. It should be noted that site specific civil works are by their very nature a one-off issue and have a cost impact only on the project where they are encountered. They do not have any general impact on the costs of other projects under construction.

The remainder of the revision relates to the use of the revised BPOs to estimate the total cost for the project. As these BPOs were revised in June 2006 we consider that they reflect current prices and hence provide a reasonable indication of current costs. We therefore consider that the total revised estimate for project CP.1294 of $47.35 million, which excludes any contingency allowance for construction uncertainties, to be reasonable and, if the project is completed within the revised estimate, the costs to be efficient. The revised estimate does not include the 2.6% estimation risk factor.

4 A PIR (Preliminary Information Request) estimate is a desk top estimate based on plans, maps, photographs and any in-house knowledge of the site.

2.1.5.3 *CP.1134 - South Pine 110kV Substation Refurbishment*

The revision of the total cost estimate to complete this project is a result of the revision of the BPOs as at June 2006.

The South Pine substation consists of a 275 kV and a 110 kV switchyard. The 110 kV switchyard is a bulk supply point for Energex and supplies customers on the north coast and the northern suburbs of Brisbane. The 110 kV switchyard was established in 1963 and the original equipment is over 40 years old.

The condition and performance of these assets has reached a stage where some replacement and upgrade is necessary to maintain quality of supply. In addition the 110 kV outdoor switchgear can no longer be supported with spare parts and a rebuild is considered the most cost effective method to rectify the situation.

Powerlink has considered viable options and the refurbishment project involves primarily:

- replacement of 110kV buswork and structures, excluding power transformers and capacitor banks;
- increasing the fault level to 40kA for 1 sec;
- replacement of current and voltage transformers;
- replacement or upgrade of foundations, footings and earth grid to achieve required ratings and 40 year life.

The initial estimate for these works was $33.98 million but the project has been re-estimated using BPOs which were revised in June 2006 and hence reflect current prices. The revised total project estimate is $38.33 million.

The increased costs included in the supplementary revenue proposal to complete this project are $5.67 million (nominal) in 2008, $5.626 million (nominal) in 2009 and $0.01 million (nominal) in 2010.

Comment

As this project was re-estimated using BPOs revised in June 2006 we consider that the revised cost reflects current pricing. Hence the revised estimate of $38.33 million for the total project appears reasonable and, if the project is completed within the revised estimate, the costs appear efficient. The revised estimate does not include any contingency allowances nor the 2.6% estimation risk factor.

Equipment such as current and voltage transformers are purchased on recently negotiated period contracts. A period contract usually indicates expected quantities to be purchased annually and fixes prices for a set period, usually three years. Powerlink has provided information on the escalation clauses in these period contracts as they relate to current transformers and circuit breakers. We have reviewed these contracts and consider the escalation clauses to be reasonable and in accordance with normal business practice.

2.1.6 CP.1138 SEQ Augmentation

The revision of the estimate of the total cost to complete this project is a result of applying a general percentage increase for lines projects, developed on the basis of individual escalators being applied to each component of the project.

South Eastern Queensland is heavily dependent on the transmission network for its electricity supply, in that only about 30% of the energy consumed in the area during peak demand periods can be produced by local power stations.

Powerlink identified an emerging limitation in the transmission network supplying the South Eastern Queensland area and corrective action is required to maintain acceptable voltage stability margins as the load continues to grow.

Powerlink undertook a planning and public consultation process in accordance with the requirements of the National Electricity Rules and Regulatory Test to determine the most efficient option to address the emerging need. The process demonstrated that construction of a new double circuit 275 kV transmission line from Middle Ridge to Greenbank and associated substation works in late 2007 followed by the installation of capacitor banks in South East Queensland in 2009 and 2010 was the least cost solution.

The Board approved a total budget of $109.9 million (at completion and including contingency) in November 2005, subject to satisfactory completion of the Regulatory Test consultation process and Shareholding Minister approval. These conditions were met on 18 January 2006 and 24 February 2006, respectively.

This project was originally estimated to cost $99.96 million and has been re-estimated using the BPOs which were revised as at June 2006. The revised estimate is $115.95 million, which is a 16% increase over the original estimate. These estimated construction costs do not include any contingency amounts.

A detailed breakdown of the original and revised estimates were provided to us by Powerlink and show that substantial increases occurred in the costs of aluminium, steel and external labour as a result of the current peak prices being experienced for these materials and the current tight market for skilled construction staff.

Comment

We have reviewed the methodology used by Powerlink to determine the BPOs and also reviewed the method used to update them. This issue is discussed in detail in Section 2.2. We believe the BPO process is sound and auditable and results in BPOs reflecting the prices of material and labour costs at the time they are reviewed. Hence they reflect current costs and are suitable for revising cost estimates for works currently in hand.

The process Powerlink has used to re-estimate lines projects where the TCE has not yet been agreed appears reasonable and we agree that applying the 16% increase to the total original estimate also appears a reasonable approach to determine current total construction costs for lines project currently under construction.

Our opinion is based on the premise that estimating line type projects lends itself much more readily to the use of unit (per kilometre) rates and percentage increases than substation projects which, by their very nature, are site and project specific. We therefore agree that applying a percentage increase to lines projects based on a typical line project, and re-estimating substation projects using revised BPOs is a reasonable approach to re-estimating projects in the absence of a TCE.

2.1.7 Conclusion

We have reviewed the three methodologies used by Powerlink to re-estimate the total costs of projects under construction and found them to be reasonable and auditable. Each method appears appropriate for the type of project to which it has been applied and, in the case of lines projects in the early stages of construction, the use of a percentage increase in total costs based on the percentage increase in costs of a typical project also seems reasonable.

In the case of substation projects, the use of BPOs revised as at June 2006 will reflect current prices and costs and hence will result in the revised estimate also reflecting current costs.

In addition we have carried out a detailed review of four projects, including the three we suggested, CP.1087 Bohle River to Townsville GT 132kV line, CP.1294 Strathmore 275kV SVC, and CP.1134 South Pine 110kV Substation Refurbishment and the additional typical lines project, suggested by Powerlink, CP.1138 SEQ Augmentation. This latter project was the typical lines project which was used to determine the percentage increase applied to lines projects that were in the early stages of construction. These reviews indicated that Powerlink has applied the appropriate methodology in a consistent manner when revising the total project estimates.

Accordingly we believe that Table 2.2, which has been revised to reflect the removal of the contingency allowance included in the revised estimate for project CP.01087, reasonably reflects the impact of applying these estimate review methodologies to the projects currently under construction and does not include contingencies for increases in project scope. Provided the projects currently under construction are completed within estimate, we consider the project costs to in the supplementary revenue proposal to be efficient.

Table 2.2: Impact of Increased Costs of Projects under Construction ($ million, real 06/07)

	2007/08	2008/09	2009/10	2010/11	2011/12	Total
Increased costs of projects under construction	87.86	61.78	6.11	(0.22)	(0.09)	155.43

Source: PB Associates based on Powerlink Supplementary Submission.

The negative amounts in years 2010/11 and 2011/12 are due the fact that re-estimating several projects has resulted in reduced annual expenditures. In these years, where overall expenditures for assets currently under construction are very small, summation has resulted in small negative totals.

Furthermore, the total revised additional expenditure of $155.43 million (real 06/07) includes the 2.6% estimation risk factor for six projects currently under construction, namely CP.00736, CP.01067, CPO.01243, CP.01265, CP.01285, and CP.01837.

We therefore recommend that the total increase in estimated costs for the projects currently under construction as calculated by Powerlink, namely $155.58 million (real 2006/07 dollars) be adjusted for the removal of the contingency sum included in forecast expenditure for the next regulatory period for project CP.01087, namely $160,000. The adjusted total increase in the forecast cost of projects under construction for the next regulatory period is therefore $155.43 million (real 2006/07 dollars) and we consider this amount to be reasonable and efficient. The total contingency provision for project CP.01087 included in the Supplementary Proposal was $1.5 million. Therefore, we also recommend that the provision for expenditure on projects under construction at the end current regulatory period be reduced by the remainder of the contingency sum for project CP.01087, namely $1.34 million.

2.2 COST INCREASES FOR FUTURE PROJECTS

In its supplementary revenue proposal, Powerlink also applied its revised BPO costs to projects that commence expenditure in the next regulatory period. In revising its BPO costs Powerlink used metal and labour indices current as at June 2006 and then benchmarked these against current costs for assets under construction including transmission lines and substation projects. Powerlink has estimated that the resulting change in BPOs results in an increase of $126 million (real 2006/07) in the forecast project costs in its original revenue proposal. There are no other changes incorporated into this adjustment other than those relating to the revision of the BPOs, i.e. there are no project scope changes. A complete list of the cost increases for future projects is included in Appendix B.

2.2.1 Revised Unit Costs

Powerlink uses very a large number of BPOs to determine project cost estimates. For intellectual property reasons, it would not provide us with a copy of its estimating manual but instead it provided detailed cost estimates for two projects, one lines and one substation, which use typical BPOs. For each of these projects two estimates were provided, one based on the BPOs used in the original revenue application and another on the revised BPOs. Powerlink advised that these projects are representative of their respective class of project and use BPOs typical of those used in estimating similar capital projects. Hence we have based our recommendations on the effect on these typical projects.

We also investigated the process used by Powerlink to revise BPOs and found this process to be appropriate and auditable. Each BPO is broken down into its basic components such as aluminium, copper, steel, concrete poles, establishment costs, internal labour and external labour. The updating process consists of updating metal indices and labour rates to values of the day and then checking the outcome to ensure the updates produce estimates in line with current estimates being received from construction contractors.

Indices from the London Metal Exchange are used to update copper and aluminium prices, and the CRU International Steel Price Index Futures (CRU spi) is used for steel. The CRU spi, not only tells you what is happening to steel prices but where it is happening and in which products. Powerlink primarily uses long steel products in the construction of transmission line towers and substation structures, and reinforcing steel in foundations and footings. A small amount of steel is also used in steel reinforced aluminium (ACSR) conductor. Long steel products include structural rolled beams, angles, channels and rods.

Labour rates and conditions are also updated to reflect current award rates and current indirect costs such as site allowances, accommodation expenses and travelling allowances.

Substation construction material[5] (excluding electrical equipment items) and labour cost indicators exhibited large percentage increases. However, the percentage of the total BPOs represented by both construction material and contract labour are both 10%, so these changes each represent approximately 5% of the increase in the total substation BPO costs. These cost increases resulted from an adjustment to align the resulting substation works estimates with current costs being provided by contractors.

The update methodology used by Powerlink does not require subjective judgment or personal opinion and leaves a clear audit trail. As noted in Section 2.1.7 of this report, we believe this process and the use of BPOs results in estimates being produced which reflect current pricing and are suitable to estimate projects currently under construction producing reasonable outcomes. However, metal prices are clearly coming off their peaks and the upward pressure on labour rates should ease in the short term. Hence BPOs current as at June 2006 do not necessarily reflect future prices (expressed in real terms) over a four to five year time frame.

2.2.2 Itemisation of Revised Unit Costs

As stated above, Powerlink did not provide us details of all of the BPOs due to intellectual property concerns and it is therefore not possible to itemise the impact of the June 2006 revision on the BPOs. However details of the application of these revised BPOs to two typical projects, one lines and one substation project, were provided and the resultant impact on the total project estimates can be seen.

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5 Substation construction materials include all materials used in the construction of substations excluding the electrical equipment (such as transformers) and civil works. It includes cables, conduits and troughs, nuts, bolts and cable terminations etc.

The lines project was CP.1512: Strathmore – Ross. The base case for this project increased from $125.43 million (05/06) to $133.97 million (05/06), an increase of 6.8%. The substation project detailed was CP.1958: Larcom Creek 275-132 kV Substation Establishment. The base case for this project increased from $43.69 million (05/06) to $49.13 million (05/06), an increase of 12.7%.

2.2.3 Appropriateness of Revised Unit Costs

2.2.3.1 Labour Costs

The market for skilled electrical construction workers is currently very tight. In such a tight labour market, we consider that it would be relatively easy to negotiate well above average site allowances, accommodation allowances and travelling conditions. This may in part account for the high labour costs being included in the TCEs currently being negotiated with Powerlink by its contractors.

However, in the context of this review an issue is whether the current tight labour market is part of a normal economic cycle or whether it represents a more fundamental and sustained change in the Queensland economy, particularly as it affects the electric power industry. If the current tight market is part of an economic cycle then, over time, escalation rates can be expected to trend back to long term averages. However if a more fundamental change is occurring then escalation rates that are currently being experienced could potentially be sustained.

The current shortage of skilled labour has been brought about by a combination of conditions, in the most part related to the high level of activity in infrastructure construction and refurbishment throughout the whole of Australia as well as the mining boom in Queensland and Western Australia. However, we do not believe that the current conditions will persist for the entire duration of next regulatory period. The cyclical nature of economic activity is caused in large measure by participants responding to alleviate economic pressures as they occur and already there is evidence that companies have in place strategies to mitigate the current tight labour market conditions for skilled electricity workers. For example, DNSPs and TNSPs throughout Australia have commenced comprehensive apprentice training programs and some have also commenced overseas recruitment programs. We believe that these programs will start to have an impact on the current tight labour conditions within the next few years.

In addition large mining companies such as BHP, which have traditionally only recruited within Australia, have decided to commence using the "457 visa" scheme to recruit foreign workers, including electricians. In an article in the Australian Financial Review of February 2, 2006, BHP announced that it would be approaching the Federal Government to assist its contractors recruit 200 foreign workers under the "457 visa" arrangement. The article states,

> *"The move, one of the largest single applications under the governments section 457 temporary visa scheme, is aimed at averting the recent construction cost blow-outs that have hit most major resources companies.*
>
> *BHP Billiton is likely to target trades such as mechanical fitters, welders and electricians from overseas to work on the project….."*

The article also includes a list of seven other major companies that have commenced to recruit foreign workers under the program including Rio Tinto, IBM, and Woodside Petroleum.

We also note Powerlink's comments that the contractors it uses also employ skilled workers recruited under the "457 visa" scheme. We believe that the "457 visa" scheme in conjunction with other the other initiatives described here will result in an alleviation of the current tight supply conditions existing for skilled electricity workers in the next two to three years. Powerlink has recently advised that its contractors pay such workers at the same rates as locally recruited labour.

In the light of these developments, we believe that the current tight market conditions for skilled electrical construction workers will persist only for the next two or three years. Accordingly we do not consider that the use of BPOs, revised as at June 2006, is appropriate to forecast future capital expenditures over the next regulatory period, as these BPOs reflect an unusually tight market for skilled labour, particularly skilled electricity workers. In forming this opinion we have also reviewed Section 2.5 of the Powerlink submission to the AER Draft Decision and Section 3 of TransGrid submission on the AER Draft Decision.

The Powerlink submission forecasts future labour costs for two classes of workers. The first class, Powerlink's permanent employees, are usually motivated by tenure of employment and the working conditions offered by employers such as Powerlink. These include comprehensive superannuation arrangements, long service and sick leave conditions and benefits such as the provision of uniforms, tools and transportation. These employees are generally representative of the utilities sector.

The other class of workers for which labour costs are forecast in the original Powerlink revenue application are contractors construction staff. These workers are generally motivated by the opportunity to earn above average wages as a result of the availability of additional payments such as living away from home and site allowances and the opportunity to access large amounts of overtime. Typically, these workers do not enjoy continuity of employment with a single employer and have to be prepared to move to the work when and where it is available. These employees are generally representative of the mining and construction industry.

Furthermore we note that almost all training of electrical apprentices and trainees is carried out by network service providers such as Powerlink and Ergon Energy and to a much lesser extent by very small residential electricians. Construction contractors generally do not have comprehensive apprentice training programs in place and rely on recruiting and attracting skilled and qualified workers from these sources.

We also agree that in the initial stages of a substantial apprentice training program there can be a reduction in overall workforce productivity, but as the first apprentices reach the final years of their training this situation reverses and total workforce productivity starts to increase. Total workforce capability continues to increase significantly as apprentices complete their apprenticeships and gain further experience and even become involved in training further apprentices. Nevertheless we still believe that the current tight supply of trained electrical workers will be alleviated within the next two to three years by the combination of the now well advanced comprehensive apprentice training programs, continuation of current overseas recruitment programs, and expansion of the 457 skilled worker visa program. We understand that the 457 visa program has already attracted approximately 40,000 skilled workers to Australia.

We also agree with TransGrid that the apprentice training program, on its own, will not solve the current shortfall in trained electricity workers. However, our view is that these programs in combination with the continuation of overseas recruitment programs and the expansion of the 457 skilled workers visa program by companies such as BHP, Rio Tinto and Woodside Petroleum, who are all involved in major infrastructure construction, will result in rebalancing the demand/supply situation for skilled electricity workers.

We note that the tight labour market affects not only the electrical trades, but also other works such as riggers and plant operators, who are required to complete transmission line and substation construction projects. However the lead times to qualify these types of worker are much shorter than for electrical tradespersons, which means that employers ability to respond to market conditions is greater. Generally competent labourers are offered the prerequisite training to acquire the licences to act as riggers and plant operators.

On this basis our view remains that the current tight market conditions for skilled electrical construction workers will not persist for the entire duration of the next regulatory period but for only the next two or three years.

2.2.3.2 Material Costs

Further to the London Metal Exchange (LME) Charts included in our review of the Powerlink's original revenue application, we have identified two additional sources of information relating to metal prices. Firstly, the weekly aluminium and copper weekly prices on Comex clearly show that prices for these two metals peaked during 2006 and have clearly dropped since the most recent peak prices were achieved. Current aluminium and copper weekly price charts are shown in Figure 2.1 and Figure 2.2 below. This trend confirms the trends evident in the price history charts obtained from the LME.

In addition, we refer to the December Quarter 2006 ABARE Commodities Report which states in regard to aluminium prices in 2007:

> *In 2007, aluminium prices are forecast to fall by 11% to average around US$2,260 a tonne (US103c/lb) as global aluminium production is forecast to exceed consumption, resulting in a moderate increase in stocks.*

In regard to copper prices the same report states:

> *In 2007, global copper prices are forecast to fall by over 8% to average US$6,250 a tonne (US284c/lb). Despite the continued likelihood of disruptions to supply because of labour disputes and a shortage of copper concentrates, world refined production is forecast to increase in 2007 by nearly 5%.*

In relation to steel prices the ABARE Report indicates that steel prices will only fall marginally in 2007 as follows:

> *World steel prices are expected to fall only marginally in 2007 from the relatively high levels in 2006.*

This information supports our recommendation in regard to projects currently under construction, insofar as these peak metal prices will be reflected in current costs for manufactured electrical materials such as transformers and cable. These high material costs have been factored into the BPOs as they were revised in June 2006. The majority of the remaining expenditure on assets currently under construction will occur within the next two years, whereas expenditure on projects that will not commence during the current regulatory period will generally occur later.

On balance, the data also indicates that the use of the BPOs revised in June 2006 that reflect the peak metal prices, are not representative of the situation going forward into the next regulatory period, since over time material prices will revert to long term averages. Hence we continue to support our recommendation made in relation to material costs in our review of Powerlink's original revenue proposal, where we concluded that over time material prices would remain constant in real terms.

In addition, the escalation clauses contained in the examples of the current period contracts, ranging from 3% per annum to 0.3% per month align closely with current levels of CPI which adds further weight to our recommendations.

Figure 2.1: Comex Weekly Aluminium Prices

Figure 2.2: Comex Weekly Copper Prices

2.2.4 Efficiency of Application of Revised Unit Costs

In our review of Powerlink's original revenue application we concluded that the BPOs used by Powerlink to estimate future projects were appropriate and benchmarked well with other publicly available cost information. Powerlink's BPOs were based on data current as at October 2005 for substation BPOs and February 2006 for line BPOs. However we note that metal prices peaked in early 2006 and that total labour costs, particularly indirect labour costs, were under upward pressure and hence we support the revision of total estimated project costs for assets under construction, based on data as at June 2006, as proposed by Powerlink. However, while we support the use of the increased BPOs for estimating the cost of projects currently under construction, we cannot support the application of these increased BPOs to forecast the cost of project that have not yet commenced.

Metal prices have now declined from the peaks in mid 2006 and the price of futures metal contracts indicate that these reductions are likely to continue. We acknowledge that forecasting future metal prices is difficult and that metal price forecasters have had a poor record for forecasting accuracy. However, in our view, this does not justify locking in peak prices when forecasting future costs, particularly when the available evidence indicates that prices will most probably fall.

In Section 4.8 of our original report, we commented on future labour costs and concluded that we did not support the proposition that they would keep increasing over the full duration of next regulatory period at the same rate as over the last two or three years. Hence we recommended adjusting Powerlink's labour escalation factors down. Table 4.3.1 of the original report details our recommendations in regard to labour escalation rates and Table 4.3.2 indicates the impact of our recommendations on forecast capex. As detailed above we believe that the training programs that are now in place in most distribution and transmission businesses, their international recruitment programs combined with the expansion and the increasing use of the current foreign skilled workers recruited under the "457 visa" program will reduce the shortfall in trained and skilled electricity workers and result in a reversion to historical long term trends in total labour costs. We have not been presented with additional data which would support changing our opinion that current market conditions are indicative of a normal short term cyclical variation and do not indicate a more fundamental and sustained economic change. We therefore do not recommend any changes to our previous recommendation in regard to labour costs.

The cost accumulation model basically has other costs which includes all other costs except labour and property increasing in line with inflation i.e. remaining constant in real terms. We have not found or been presented with any additional information which would change our opinion in this regard and hence would not recommend any changes to our previous recommendations in regard to material costs forecasts.

2.2.5 Conclusion on Review of Future Projects

Table 2.3 details the additional forecast capital expenditure requested by Powerlink as a result of the revision of BPOs using data current as at June 2006. We have not been presented with any additional information or data which we believe would warrant changing our previous recommendation in respect of the costs of projects that are forecast to begin during the next regulatory period.

Table 2.3: Impact of Unit Rate Increases in Forecast Capex Proposed by Powerlink

$ million (06/07)	2007/08	2008/09	2009/10	2010/11	2011/12	Total
Future Projects	10.37	24.97	30.40	32.71	27.06	125.52

Source: Powerlink Supplementary Revenue Application

We consider that the use of BPOs current for lines projects as at February 2006 and BPOs for substation projects revised as at October 2005 more accurately reflect prices and costs likely to be experienced for the next regulatory period when inflated in accordance with our recommendation in Section 4.8 of our previous report.

Hence we do not support Powerlink's request to increase the forecast capital expenditure allowance as a result of revising its BPOs as at June 2006 by $125.52 million (real 2006/07).

3. PAPUA NEW GUINEA (PNG) GAS PIPELINE PROJECT

As part of its supplementary revenue proposal, Powerlink identified that significant (adverse) developments in the PNG gas pipeline project had occurred subsequent to the submission of its original revenue application. The estimated project cost had blown out by more than 50% and AGL had decided to withdraw from the front end engineering and design (FEED) activities and write off its incurred costs to date. As a result, Powerlink now considered that the PNG gas pipeline project would not result in any associated generation developments in the Townsville area within the next regulatory period. Since Powerlink's original revenue proposal had been based on an assumed 50% probability of the pipeline project being completed before July 2010 and associated generation materialising as a result, it considered its capital expenditure requirements should be reviewed to account for a zero probability of the PNG theme set.

Powerlink therefore re-evaluated its forecast capex on the basis of a zero probability of the generation associated with the PNG gas pipeline project occurring within a timeframe to affect expenditure within the coming regulatory period. In general, it identified more grid augmentation was required between CQ and NQ and less augmentation was required between CQ and SQ. This outcome was primarily driven by the decreased likelihood of new gas fired generation being developed in NQ and a corresponding increase in the likelihood of new generation in SQ. The net impact of Powerlink's proposed revision is shown in Table 3.1.

Table 3.1: Impact of revised probability for generation associated with the PNG gas pipeline project on its total forecast capital expenditure

$ million (06/07)	2007/08	2008/09	2009/10	2010/11	2011/12	Total
Change in total capex – PNG theme set	(0.25)	2.60	36.17	18.39	(0.13)	56.78

It is important to note that these changes assume that the total regulatory capex has already been adjusted for:

- The CQ-SQ revision; and
- Increased input costs for work-in-progress and future projects.

3.1 REASONABLENESS OF UPDATED PROBABILITY

In reviewing the reasonableness of Powerlink's proposal to modify the probability of the PNG theme set to zero, we have considered four factors:

- The history of the probability;
- The matters considered by Powerlink in drawing its conclusions;
- Recent advice from ROAM Consulting; and
- Recent and relevant press releases by the project proponent Oil Search Limited.

3.1.1 The History of the Probability

Powerlink's capital expenditure forecast has been based on a probabilistically weighted assessment of 40 network development scenarios, which were underpinned by 40 generation development programs associated with the various conditions represented in defined market development scenarios. The scenarios and generation development programs were prepared by NEM forecasting specialist, ROAM Consulting, who also assessed the probability of each scenario proceeding.

The initial report prepared by ROAM Consulting for Powerlink was completed in September 2005[6], and adopted a 20% likelihood of generation associated with the PNG gas pipeline project proceeding prior to July 2010. As a consequence of significant developments related to the pipeline project during the second half of 2005, ROAM Consulting was engaged by Powerlink to update the probabilities associated with its market development scenarios. It reported to Powerlink in February 2006[7] that it considered the likelihood of the generation associated with the PNG gas pipeline project proceeding should be increased to 50%. Powerlink then incorporated these recommendations into its network development planning processes, and subsequently arrived at the forecast of capital expenditure in its original revenue application. The consequence of this increased probability was a reduction in Powerlink's total capex forecast, which was primarily driven by the increased likelihood of new gas fired generation being developed in NQ.

3.1.2 Powerlink's Considerations

As outlined in its supplementary revenue proposal, Powerlink based its proposal to modify the probability of the PNG theme set to zero on:

- The inability of the proponent to secure firm customer contracts;
- The project cost blow-out, reported to be more than 50%, indicating a total cost of over $5 billion;
- AGLs withdrawal from the front end engineering and design (FEED) activities and the write off of its incurred costs to June 30 2006; and
- The proponents consideration of a staged development and alternative routes.

Powerlink's opinion was also anecdotally supported by various media reports.

3.1.3 Updated Advice from ROAM Consulting

As part of Powerlink's ongoing consideration of the PNG gas pipeline project, and given its critical role in proposing the original theme based probabilities, ROAM Consulting was engaged by Powerlink in the second half of 2006 to advise it on the likelihood of the pipeline project proceeding within the next regulatory period and, more generally, on the impact on generation development within the Townsville region.

ROAM Consulting's complete advice on this matter is included in Appendix D, but in general the following conclusions were provided:

> *"ROAM Consulting believes that the likelihood of the PNG project supplying gas to Townsville before the end of the next regulatory period is*

6 ROAM Consulting, September 2005, *NEM Forecasting – Identification of Generation Development Scenarios.*

7 ROAM Consulting, February 2006, *NEM Forecasting – Scenario Analysis Revisions for PNG Pipeline Developments*.

> *sufficiently remote to warrant a 0% probability in Powerlink's planning process."*

With respect to modelled generation in the Townsville area, it also concluded that:

> *"ROAM Consulting therefore considers that it is appropriate for the Townsville South station to remain as a generation project under those scenarios where demand is at its highest, irrespective of whether or not those scenarios also contains the PNG pipeline project."*

With respect to existing gas supplies to Townsville, it concluded that:

> *"..the only field capable of supplying gas to Townsville is the Moranbah Gas Project. As of December 2005 the MGP had 382 PJ of P2 reserves, of which circa 290 PJ were dedicated to Enertrade under its gas supply agreement leaving an available balance of 92 PJ for new projects. For the 400MW CCGT Townsville South project to be bankable it would require circa 20 PJ of gas each year for a term of twenty years. With only 92 PJ available from the MGP the station could be fuelled for less than five years."*

Furthermore, with respect to alternative gas supplies to Townsville, it concluded that:

> *"ROAM Consulting does not consider that the prospective Moranbah to Gladstone Gas Pipeline[8] at present represents a reliable source of gas into Townsville within the regulatory period."*

3.1.4 Oil Search Limited Press Release

During our review of Powerlink's supplementary revenue proposal, Oil Search Limited, a business incorporated in Papua New Guinea, and the majority stakeholder in the PNG gas pipeline project, published a press release (01 February 2007) on the status of the development. The release is included in Appendix E.

In the press release, Oil Search Limited advised:

> *"The PNG Gas Project participants have recently completed an intensive review of development options for the PNG Gas Project..,*
>
> *Oil Search and its partners have … identified a number of projects that have demonstrably higher value and return potential than the PNG Gas Project to Australia. …*
>
> *In light of the superior returns that may be achieved from these alternative opportunities, the PNG Gas Project participants have agreed to suspend work on the Project and concentrate development of the Hides and Kutubu resource into higher value projects. As such, the agreement that links the Hides and Kutubu fields to underwrite reserves for the Project has not been renewed."*

Given this announcement, and the other factors considered in the lead up to it, we consider it reasonable that Powerlink modify the probability of the PNG theme set to zero in determining its probability weighted forecast capex.

8 Nevertheless, the prospective Moranbah to Gladstone gas pipeline project would provide the Townsville area with access to gas from south of Gladstone, via the Moranbah to Townsville gas pipeline.

3.2 PROJECTS IMPACTED BY REVISED PNG PROBABAILITY

One strength of the probabilistic approach adopted by Powerlink in its forecast capex model is the ability to quickly and easily quantify sensitivities to input assumptions through the high level review and adjustment of the models input assumptions. This is the approach that has been adopted by Powerlink to determine the impact of revised generation associated with the PNG gas probability. No new transmission or generation based projects were proposed, and the timing of all original projects was maintained constant. All projects within the probabilistic model were impacted by the change in the theme set probability[9].

The probabilistic themes adopted by Powerlink in its original revenue application are shown in Table 3.2.

Table 3.2: Probabilistic Themes Adopted by Powerlink

Theme Set	Themes	Initial Probability	Moderated Probability
Load growth	Low Growth, 50% POE	20%	23.93%
	Medium Growth, 50% POE	35%	37.09%
	Medium Growth, 10% POE	25%	20.74%
	Medium Growth, 50% POE, plus 500 MW prior to 2009/10 and further 500 MW prior to 2010/11	10%	10.97%
	High Growth, 50% POE	10%	7.28%
Inter-regional trade	Existing QNI transfer of 300 MW to Qld.	70%	65.50%
	Increased QNI transfer (+500 MW to Qld) prior to 2010/11	30%	34.50%
Gas supplies	No PNG pipeline driven generation development	50%	53.54%
	New generation (but no load) development associated with PNG pipeline timing prior to summer 2010/11.	50%	46.46%
Greenhouse options	No Greenhouse tax	80%	87.24%
	Introduction of greenhouse tax	20%	12.76%

The total number of scenarios is determined from the combination of each of the four themes (i.e. 5 x 2 x 2 x 2 = 40), and each scenarios top down weighting is determined by the product of the likelihood of each condition within each theme set.

Given the tight time constraints associated with the preparation of Powerlink's supplementary revenue proposal, rather than reviewing the new scenario probabilities in an identical fashion to the original application (which was performed by ROAM Consulting), Powerlink simulated the moderation process using the following sequential methodology:

- It determined the % change[10] to the original scenario probabilities introduced by ROAM Consulting's specialist moderation[11] of the top down (PNG 50%) weightings (refer column 4 in Table 3.3);

9 Technically, the 20 scenarios which included PNG gas had their probabilities reduced to zero, while the remaining 20 scenario probabilities increased.

10 The '% change' was tested for three sets of top-down and moderated probabilities supplied by ROAM Consulting and found to be fairly constant

11 This moderation was undertaken to account for the uncertainty related to actual generation projects within each theme, to maintain expected bounds of reserve plant margins and to maintain the bounds of practical power station sizes.

- It determined new top down weightings for each scenario for the PNG 0% condition (refer column 5 in Table 3.3);

- It simulated the application of the ROAM moderation by adopting the product of the % change previously determined and the PNG 0% top down (refer column 6 in Table 3.3);

- It scaled each scenarios probability down by 7.08%[12] to ensure the summated probabilities still equalled 100% (refer column 7 in Table 3.3); and

- Finally it adjusted the scaled scenario probabilities in three groups (low scenarios 1-8, medium scenarios 9-32, and high scenarios 33-40) to ensure these groups maintained the same proportions as were in the original moderated PNG 50% version of probabilities (refer column 8 in Table 3.3). Powerlink advised that the reason it applied this final adjustment was to ensure that the PNG theme set did not impact on the probability weighted capex of projects that are dependant on load growth only (i.e. independent of generation development).

Column 1 in Table 3.3 presents the arbitrary scenario number, column 2 shows the original top down weightings assuming the PNG theme likelihood of 50%, and column 3 and 4 show the impacts of ROAM Consulting's specialist moderation.

As an example, the top down weighting of 5.60% for scenario 1 assuming the PNG gas pipeline project theme set likelihood of 50% has been determined through the following product: (L50 x QNI x No PNG x No Tax) = 20% x 70% x 50% x 80% = 5.6%. With the revised PNG gas pipeline project theme set likelihood of 0%, the updated product is: (L50 x QNI x No PNG x No Tax) = 20% x 70% x 100% x 80% = 11.2%.

For the avoidance of doubt, Powerlink has not actually applied any of the top-down weightings to determine its probability weighted capital expenditure forecasts. It has used moderated probabilities determined by ROAM Consulting (see column 3) for this purpose except when quantifying the impact of the revised PNG gas pipeline project probability as part of its supplementary submission – in this case it has attempted to simulate the moderation using the described and outlined process within Table 3.3 (see column 8).

12 This is the difference between the summation of the 1st pass moderation scenario probabilities and 100%, as shown in the final row of Table 3.3.

Table 3.3: Determination of new probabilities as a result of PNG theme reducing from 50% to 0%.

Scenario	Revenue Application top-down PNG 50%	ROAM moderation	% change	PNG 0% top-down	1st pass moderation	scaled to achieve 100%	Final adjustment
Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8
1	5.60%	7.88%	40.65%	11.20%	15.75%	14.71%	14.21%
2	1.40%	1.10%	-21.66%	2.80%	2.19%	2.05%	1.98%
3	5.60%	6.78%	21.07%	-	-	-	-
4	1.40%	1.10%	-21.66%	-	-	-	-
5	2.40%	3.79%	57.86%	4.80%	7.58%	7.08%	6.84%
6	0.60%	0.50%	-16.92%	1.20%	1.00%	0.93%	0.90%
7	2.40%	2.29%	-4.45%	-	-	-	-
8	0.60%	0.50%	-16.92%	-	-	-	-
9	9.80%	10.87%	10.89%	19.60%	21.73%	20.30%	20.38%
10	2.45%	1.50%	-38.96%	4.90%	2.99%	2.79%	2.80%
11	9.80%	10.07%	2.75%	-	-	-	-
12	2.45%	1.50%	-38.96%	-	-	-	-
13	4.20%	5.88%	40.06%	8.40%	11.76%	10.99%	11.03%
14	1.05%	0.90%	-14.54%	2.10%	1.79%	1.68%	1.68%
15	4.20%	5.58%	32.93%	-	-	-	-
16	1.05%	0.80%	-24.04%	-	-	-	-
17	7.00%	6.68%	-4.57%	14.00%	13.36%	12.48%	12.52%
18	1.75%	0.80%	-54.42%	3.50%	1.60%	1.49%	1.50%
19	7.00%	4.89%	-30.21%	-	-	-	-
20	1.75%	0.70%	-60.12%	-	-	-	-
21	3.00%	3.79%	26.29%	6.00%	7.58%	7.08%	7.10%
22	0.75%	0.50%	-33.53%	1.50%	1.00%	0.93%	0.93%
23	3.00%	2.89%	-3.62%	-	-	-	-
24	0.75%	0.50%	-33.53%	-	-	-	-
25	2.80%	3.39%	21.07%	5.60%	6.78%	6.33%	6.36%
26	0.70%	0.40%	-43.03%	1.40%	0.80%	0.74%	0.75%
27	2.80%	2.89%	3.26%	-	-	-	-
28	0.70%	0.40%	-43.03%	-	-	-	-
29	1.20%	1.69%	41.24%	2.40%	3.39%	3.17%	3.18%
30	0.30%	0.30%	-0.30%	0.60%	0.60%	0.56%	0.56%
31	1.20%	1.60%	32.93%	-	-	-	-
32	0.30%	0.30%	-0.30%	-	-	-	-
33	2.80%	1.99%	-28.79%	5.60%	3.99%	3.72%	4.04%
34	0.70%	0.30%	-57.27%	1.40%	0.60%	0.56%	0.61%
35	2.80%	1.99%	-28.79%	-	-	-	-
36	0.70%	0.30%	-57.27%	-	-	-	-
37	1.20%	1.10%	-8.61%	2.40%	2.19%	2.05%	2.22%
38	0.30%	0.20%	-33.53%	0.60%	0.40%	0.37%	0.40%
39	1.20%	1.20%	-0.30%	-	-	-	-
40	0.30%	0.20%	-33.53%	-	-	-	-
Sum:	**100.00%**	**100.00%**		**100.00%**	**107.08%**	**100.00%**	**100.00%**

It is noted that the impact of reducing the PNG probability to zero is to eliminate 20 of the 40 scenarios.

The outcome of the revised PNG theme set probabilities proposed by Powerlink is shown in Table 3.4.

Table 3.4: Adjusted Probabilistic Themes Proposed by Powerlink

Theme Set	Themes	Initial Probability	Moderated Probability
Load growth	Low Growth, 50% POE	20%	23.93%
	Medium Growth, 50% POE	35%	35.89%
	Medium Growth, 10% POE	25%	22.05%
	Medium Growth, 50% POE, plus 500 MW prior to 2009/10 and further 500 MW prior to 2010/11	10%	10.85%
	High Growth, 50% POE	10%	7.27%
Inter-regional trade	Existing QNI transfer of 300 MW to Qld.	70%	65.15%
	Increased QNI transfer (+500 MW to Qld) prior to 2010/11	30%	34.84%
Gas supplies	No PNG pipeline driven generation development	100%	100%
	New generation (but no load) development associated with PNG pipeline timing prior to summer 2010/11.	0%	0%
Greenhouse options	No Greenhouse tax	80%	87.88%
	Introduction of greenhouse tax	20%	12.12%

To quantify the annual impacts of the revised PNG theme, the deterministic capex required in each year[13] was multiplied by the previous and the updated probabilities to arrive at a weighted increase in annual and regulatory period capex. This process and the outcomes are shown in Table 3.5.

13 The deterministic capex in each year has been adjusted for the CQ-SQ review, increased costs on projects under construction and increased unit rate increases for forecast projects.

Table 3.5: Impact of revised probability for PNG gas development (on the scenario dependant network capex) ($ million real, 06/07)

Scenario	2007-08 capex	2008-09 capex	2009-10 capex	2010-11 capex	2011-12 capex	Reg. Period capex	Previous Probability PNG 50%	Updated Probability PNG 0%	Weighted Increase
1	482.7	438.4	410.3	386.7	312.7	2,030.8	7.88	14.21	128.68
2	477.9	375.5	420.0	453.5	312.1	2,039.0	1.10	1.98	17.99
3	482.7	438.4	409.5	380.8	308.6	2,020.1	6.78	-	(136.95)
4	485.3	462.1	412.2	384.8	311.8	2,056.1	1.10	-	(22.55)
5	482.7	438.4	410.9	390.6	315.6	2,038.2	3.79	6.84	62.13
6	484.5	439.6	413.2	382.1	308.9	2,028.3	0.50	0.90	8.13
7	482.7	438.4	409.5	380.8	308.6	2,020.1	2.29	-	(46.32)
8	477.9	375.5	420.3	455.1	310.9	2,039.7	0.50	-	(10.17)
9	613.2	575.3	586.1	563.3	463.6	2,801.5	10.87	20.38	266.40
10	594.6	534.3	671.5	592.2	470.0	2,862.7	1.50	2.80	37.46
11	608.1	506.3	447.6	605.9	484.6	2,652.5	10.07	-	(267.10)
12	592.5	506.5	445.5	492.2	616.5	2,653.2	1.50	-	(39.68)
13	613.2	575.1	584.3	562.1	477.9	2,812.5	5.88	11.03	144.76
14	599.6	525.3	591.3	476.6	471.3	2,664.1	0.90	1.68	20.92
15	613.1	509.3	429.1	400.9	497.6	2,450.0	5.58	-	(136.79)
16	592.5	506.5	457.4	614.1	470.9	2,641.4	0.80	-	(21.07)
17	591.8	502.0	479.3	623.4	459.9	2,656.3	6.68	12.52	155.26
18	592.5	509.8	468.4	613.6	470.2	2,654.4	0.80	1.50	18.53
19	593.3	510.1	463.9	604.1	466.7	2,638.1	4.89	-	(128.88)
20	592.5	506.5	442.6	470.7	475.3	2,487.6	0.70	-	(17.36)
21	613.2	562.5	428.2	436.7	631.3	2,671.9	3.79	7.10	88.58
22	592.5	509.8	467.8	629.9	485.4	2,685.3	0.50	0.93	11.71
23	598.4	511.3	436.5	410.8	475.7	2,432.7	2.89	-	(70.34)
24	592.5	506.5	445.5	474.9	464.5	2,483.9	0.50	-	(12.38)
25	598.4	589.5	608.1	600.1	464.3	2,860.4	3.39	6.36	84.84
26	599.4	593.7	526.9	428.2	603.7	2,751.8	0.40	0.75	9.60
27	621.7	814.5	456.6	432.0	460.7	2,785.6	2.89	-	(80.54)
28	622.1	821.8	533.5	415.5	473.4	2,866.4	0.40	-	(11.43)
29	598.4	592.1	615.9	602.3	484.8	2,893.6	1.69	3.18	42.91
30	599.2	595.7	609.6	550.3	496.9	2,851.8	0.30	0.56	7.46
31	598.0	578.2	445.3	448.9	465.5	2,535.9	1.60	-	(40.45)
32	599.5	575.5	450.6	574.7	473.4	2,673.7	0.30	-	(8.00)
33	981.4	822.6	423.4	706.1	504.2	3,437.6	1.99	4.04	70.45
34	974.6	789.8	743.9	464.7	471.4	3,444.5	0.30	0.61	10.59
35	991.2	899.9	394.1	630.9	511.4	3,427.5	1.99	-	(68.35)
36	974.6	754.0	382.4	456.8	658.5	3,226.4	0.30	-	(9.65)
37	988.0	886.6	419.0	639.3	517.7	3,450.5	1.10	2.22	38.89
38	974.6	786.3	595.3	451.6	470.6	3,278.4	0.20	0.40	6.72
39	993.3	886.6	394.1	633.8	529.6	3,437.6	1.20	-	(41.13)
40	981.5	759.4	389.5	440.4	489.1	3,059.9	0.20	-	(6.10)
Total Increase ($ million, real 06/07) :									**56.78**

The increase in the forecast total capex for the next regulatory period caused by the reduction in the probability of generation associated with the PNG gas pipeline project from 50% to zero is $56.78 million, or 2.1% based on the adjusted capex forecast of $2,689 million. The adjusted capex forecast is calculated from the original proposal of $2,449 million minus $41 million for the CQ-SQ review plus $156 million for the increased costs associated with the work in progress projects plus $125 million for the future capex projects. The adjusted network capex alone (i.e. excluding non-network capex) is $2,583 million compared with the original figure of $2,346 million.

3.3 EFFICIENCY OF REVISED PROBABILITY IMPACTS

Given that the approach that Powerlink adopted to quantify the impacts of the revised probability of the generation from PNG gas theme is consistent with that used to develop its total probability weighted forecast capex, we consider the revised outcomes generally reflect an efficient approach to network development. Powerlink has not adjusted anything within the network or generation development scenarios; it has simply applied revised scenario probabilities in a top-down approach to arrive at the new outcome. We believe the adjustment or consideration of alternative generation programmes (such as the increased use of coal seam methane generation around the Townsville area) is and was already suitably captured in the twenty remaining scenarios that reflected the PNG 0% theme.

The Townsville South 400MW CCGT (Potential Project #17) considered as part of ROAM Consulting's generation planning is still present in the high economic growth scenarios irrespective of whether the PNG gas pipeline project will proceed. We would not recommend any adjustments to the generation plan within each scenario unless a full review of the entire generation plan was carried out (i.e. the timing, capacity and probability of all 82 separate generation projects were reviewed on a systematic and consistent basis). We also note that the 40 scenarios are not necessarily mutually exclusive; for example, the removal of the PNG gas pipeline project may have some impact on the demand forecasts for North Queensland[14].

In our view, the only questionable aspect of Powerlink's approach to implementing the new PNG gas theme set probability is the need for the final adjustment to calculate the revised scenario probabilities (refer column 8 in Table 3.3). Powerlink indicated that it undertook this last step in order to maintain the summated moderated probabilities of the three load growth themes (i.e. 23.93%, 68.79% and 7.28%, for the low, medium and high economic growth themes, respectively) from the original PNG 50% case, as this would ensure that the weighted capex of projects would be dependant on load growth only and not generation. The consequence of this final adjustment has been to reduce the low economic growth theme cumulative weighting from 24.77% to 23.93%, to increase the medium economic growth theme cumulative weighting slightly from 68.53% to 68.79%, and to increase the high economic growth theme cumulative weighting from 6.70% to 7.28%, resulting in a net increase in capex of approximately $10 million.

While ROAM Consulting[15] has advised that the moderation process was calibrated around the PNG 50% case, we do not consider there is a need to retain any characteristics of the original PNG 50% case, given that this scenario is no longer valid. ROAM Consulting indicated that the calibration process resulted in counterintuitive outcomes for the high economic growth themes whereby its cumulative weighting was always reduced, irrespective of whether the likelihood of the PNG theme set was increased or decreased - and that it considers that, in the absence of undertaking detailed additional work, the probability estimates for the original low, medium and high economic growth scenarios would represent the most reliable estimates. Given the overall uncertainty associated with the use of the non-calibrated model, and highlighting that adjustments always led to a reduction in the high economic growth theme, we consider the 1st pass moderation and appropriately scaled probabilities (refer column 7 in Table 3.3) accurately capture the new theme weightings and we therefore recommend the final adjustment proposed by Powerlink not be implemented.

The consequence of this recommendation is that the increase in capex over the regulatory period is reduced from $56.78million to $46.8million.

14 While Powerlink has stated that uncertain industrial loads of the type which may be facilitated by the pipeline have not been included in the demand forecasts, it is plausible that some influence of the proposed gas pipeline was captured in the underlying economic growth forecasts projected by NIEIR.

15 Letter dated 22 February 2007, ROAM Consulting to Powerlink.

3.4 DETAILED PROJECT REVIEW

Our assessment of Powerlink's review has been informed by a detailed review of one project affected by the new PNG probability.

3.4.1 CP.01512 – Strathmore to Ross Double Circuit 275 kV line

The scope of this project involves the construction of approximately 190 km of 275 kV double circuit transmission line from Strathmore to Ross with each circuit designed with a nominal thermal rating of around 1,150 MVA continuously during summer conditions. Substation works are required at either end to allow the new lines to be switched, monitored and protected from faults. Five new 275 kV circuit breakers are required.

As part of Powerlink's original revenue application, this project was identified in 8 of the 40 scenarios, with a cumulative probability of 28%, and an estimated cost within the regulatory period of $137.56 million. The timing of the project was identified as either 31/10/2009 (high growth) or 31/10/2010 (medium growth).

Impacts of the changes in the generation associated with the PNG gas pipeline project probability on this project are shown in Table 3.6.

Table 3.6: Changes in probability of CP.01512 as a result of revised generation associated with the PNG gas theme probability

Scenario	Timing	Original Probability	New Probability	Scenario	Timing	Original Probability	New Probability
1				21			
2				22			
3				23			
4				24			
5				25	31/10/2010	3.39%	6.36%
6				26			
7				27			
8				28			
9	31/10/2010	10.87%	20.38%	29	31/10/2010	1.69%	3.18%
10				30			
11				31			
12				32			
13	31/10/2010	5.88%	11.03%	33	31/10/2009	1.99%	4.04%
14				34			
15				35	31/10/2009	1.99%	0.00%
16				36			
17				37	31/10/2009	1.10%	2.22%
18				38			
19				39	31/10/2009	1.20%	0.00%
20				40			
Summated Probability						**28.11%**	**47.21%**

Assuming the median date for project commissioning, the direct impact of the revised PNG gas theme probability on this project is to increase the probability weighted expenditure within the regulatory period from $38.67 million to $64.94 million, an increase of $26.27 million (68%), or 46% of the total capex increase sought by Powerlink.

This is a reasonable outcome and application of the updated theme set probabilities.

3.5 CONCLUSIONS ON PNG GAS GENERATION IMPACTS

Given the recent announcement by Oil Search Limited and the other PNG gas pipeline project partners regarding their agreement to evaluate other alternatives for PNG gas and suspend work on the pipeline project to Australia, we concur with Powerlink that the probability of generation from PNG gas theme set should be set to zero when forecasting its future capex requirement.

We also consider the top-down approach adopted by Powerlink (i.e. no adjustment to the scope or timing of either transmission or generation projects within its grid planning process) to be a reasonable approach to determine an efficient revised expenditure profile. This approach maintains the integrity of the probabilistic model used by Powerlink.

Ideally, Powerlink could have followed the identical process used to moderate its scenario probabilities as that used during the original review, but we agree the approach adopted was pragmatic given the time constraints and reflects a good approximation of the more detailed moderating approach adopted by ROAM Consulting. However, we consider the final adjustment to the probabilities, aimed at maintaining some characteristics of the original PNG 50% case, was not necessary and should not be made. On this basis we recommend the changes to the total capex as outlined in Table 3.7.

Table 3.7: Recommendation - Impact of revised probability for generation from the PNG gas pipeline project on its total forecast capital expenditure

$m real 06/07	2007/08	2008/09	2009/10	2010/11	2011/12	TOTAL
Proposed Change in total capex – PNG theme set	(0.25)	2.60	36.17	18.39	(0.13)	56.78
Recommended Change in total capex – PNG theme set	(3.45)	(0.05)	35.53	16.45	(1.68)	46.80
Adjustment	**(3.20)**	**(2.65)**	**(0.64)**	**(1.94)**	**(1.55)**	**(9.98)**

4. IMPACT OF DEMAND FORECASTS ON AUGMENTATIONS

Powerlink's original revenue proposal relied on demand forecasts as published in its Annual Planning Report (APR) for 2005. In its supplementary revenue proposal, Powerlink stated that it believed that the 2006 demand forecasts, published after its original revenue proposal was submitted, should be taken into account by the AER in making its final revenue cap decision. It noted that the 2006 demand forecasts advance the timing of augmentations, particularly in South East Queensland. To account for this Powerlink proposed an increase in its forecast capex of $129 million, as summarised in Table 4.1.

Table 4.1: Impact of 2006 load forecast review on total forecast capital expenditure

$m real 06/07	2007/08	2008/09	2009/10	2010/11	2011/12	TOTAL
Change in total capex – load forecasts	55.12	54.42	(57.27)	50.33	26.40	129.00

Source: Powerlink

It is important to note that these changes assume that the total regulatory period capex has already been adjusted for:

- The CQ-SQ revision
- Increased input costs for work-in-progress and future projects; and
- The revised probability of the PNG pipeline

4.1 CHANGES IN PEAK DEMAND FORECASTS

The original revenue proposal submitted by Powerlink in April 2006 was based upon the demand and energy forecasts as outlined in its APR 2005. The forecasts cover a 10-year planning period and three economic growth scenarios – high, medium and low. Within each of these economic growth scenarios there are three sub-scenarios that capture the long run average weather conditions; namely 10% probability of exceedance (PoE), 50% PoE and 90% PoE. In all, there are nine sets for summer and winter peak demand forecasts, plus a set for energy consumption. The APR 2005 forecasts included the most recent information from distribution network service providers (DNSPs) and major customers from the summer 2003/04 and winter 2004 periods.

In June 2006, Powerlink published its APR 2006, incorporating historical experiences from the summer 2004/05 and the winter 2005 period. The changes in the updated peak summer demand projections across Queensland between the APR 2005 and APR 2006 are shown in Table 4.2, and the original forecasts from each year are included in Appendix F. It is important to note that these are state-wide forecasts based on the coincident 'as delivered' demand at any one point in time[16].

16 Due to the diversity in the location of the load centres, some areas of the network can experience demand greater than that which occurs at the time of the region's coincident peak demand. This is discussed in more detail in Section 4.1.2. The term 'as delivered' refers to the aggregated electricity demand at the points of connection and excludes transmission losses and power station auxiliary usage.

Table 4.2: Changes in the Queensland region (coincident) peak summer demand between APR 2005 and APR 2006 (MW).

	High			Medium			Low		
Summer Forecasts	10% PoE	50% PoE	90% PoE	10% PoE	50% PoE	90% PoE	10% PoE	50% PoE	90% PoE
2006/07	24	-105	-228	270	137	11	396	263	139
2007/08	39	-111	-252	255	103	-34	453	302	167
2008/09	13	-152	-305	279	116	-32	547	385	239
2009/10	-99	-275	-438	280	105	-53	580	408	255
2010/11	379	187	11	272	85	-84	591	410	251
2011/12	304	99	-89	285	85	-93	617	427	259
2012/13	258	37	-164	293	79	-110	673	471	295
2013/14	189	-47	-261	301	77	-123	709	497	313
2014/15	163	-90	-321	345	105	-105	771	549	357

Source: PB Associates, using Table 3.8 from Powerlink's APR 2006, Table 4.6 from APR 2005, and specific advice from Powerlink on the Tweed area load.

It is noted that between the publication of the 2005 and 2006 APRs, the definition of Queensland demand changed as a result of the regulation of the Directlink interconnector. The impact is that Tweed Shire electricity load (approximately 95 MW in the Medium 50% PoE case for 2006/07) is excluded from the APR 2006 forecasts. For the purposes of this report, Powerlink has provided specific advice on the demand forecasts in the Tweed Shire and they have been included in the presentation of the forecasts. On this basis, forecasts presented in this report may differ from those within the APR 2006.

Powerlink has advised the differences in summer peak demand forecasts in Table 4.2 are primarily attributed to:

- Slightly increased economic growth forecasts;
- A small increase due to resurgent commercial growth in Cairns;
- Increases related to the 'resources boom' and associated coal mine development, rail haulage, port handling and provincial population/commercial development;
- Moderated population growth forecasts in some regions and resurgence in others;
- Greater increases in new and upgraded domestic air conditioning installations; and
- The potential for a large direct connected customer increasing its demand under favourable (high) economic conditions.

Of particular note, Powerlink advises that the increased spread across the medium economic growth 10% and 90% PoE state summer peak forecast is a direct result of the increased temperature sensitivity of load, particularly in South East Queensland.

While we note the changes in peak demand forecast as outlined above, we highlight that as part of our terms of reference we have not been asked to, and did not, consider whether the changes in the forecasts, or the assumptions on which they are based, are accurate, valid or reasonable.

4.1.1 Changes in Zone Based Demand Forecasts

Powerlink aggregates the individual connection point demand forecasts supplied by the DNSPs into 10 distinct geographic zones within the Queensland region[17]. To give some relativity to the demand in the defined zones, the area of South East Queensland (comprised of Moreton North, Moreton South and Gold Coast, including the capital of Brisbane) makes up around 58% of the entire 2007/08 medium growth 10% PoE peak demand, North Queensland (comprised of North, Ross and Far North, including the regional centre of Townsville) makes up around 14% and the balance of the load is in the remaining regions, with particular note of the major industrial area of Gladstone which has a high density load of around 14% of the State demand.

Table 4.3 provides the change in these forecasts for the medium growth scenario and 50% PoE state coincident summer peak conditions. All these forecasts include the Tweed Shire demand. The original forecasts are provided in Appendix H.

Table 4.3: Changes in the Queensland (coincident) peak summer demand for the Medium growth scenario and 50% PoE conditions between APR 2005 and APR 2006 (MW).

Summer Forecasts	Far North	Ross	North	Central West	Glad-stone	Wide Bay	South West	Moreton North	Moreton South	Gold Coast / Tweed	Total
2006/07	7	-88	45	73	-93	-3	6	100	77	14	138
2007/08	7	-88	42	79	-67	-10	4	41	82	12	102
2008/09	7	-90	43	86	-71	-10	1	26	102	21	115
2009/10	7	-91	63	93	-62	-11	-1	30	63	13	104
2010/11	8	-94	60	96	-54	-12	-3	25	47	14	87
2011/12	8	-96	61	97	-55	-13	-7	22	50	20	87
2012/13	7	-100	60	99	-57	-14	-11	0	63	32	79
2013/14	7	-102	59	100	-59	-14	-16	-8	68	41	76
2014/15	10	-104	59	102	-54	-15	-19	3	71	52	105

Source: PB Associates, using Table 3.8 from Powerlink's APR 2006 and Table 4.6 from APR 2005, and specific advice from Powerlink on the tweed area demand.

Of particular note from Table 4.3 is that, while the net increase in coincident peak summer demand is relatively small (1.7% compared to the 2005 forecast for 2006/07 of 8,188MW), there is considerable variation on a zone by zone basis.

The same set of information for the medium growth scenario and 10% PoE conditions is presented in Table 4.4. The original forecasts are in Appendix I. The 10% PoE conditions are representative of more extreme weather conditions, and the associated impact of increased air-conditioning demand. Such conditions occur less frequently than the 50% PoE conditions (i.e. 1 every 10 years compared to one every 2 years). However they are the most critical with respect to the transmission capability because the demand is increased and the thermal capability of transmission plant to transfer power is reduced during hot ambient temperature conditions.

17 Refer to Appendix B for definitions and a stylised diagram of the zones.

Table 4.4: Changes in the Queensland (coincident) peak summer demand for the Medium growth scenario and 10% PoE conditions between APR 2005 and APR 2006 (MW).

Summer Forecasts	Far North	Ross	North	Central West	Glad-stone	Wide Bay	South West	Moreton North	Moreton South	Gold Coast / Tweed	Total
2006/07											
2007/08	9	-88	45	84	-63	-9	6	86	149	36	255
2008/09	9	-88	48	94	-65	-9	5	72	172	45	283
2009/10	10	-90	69	102	-54	-9	2	79	133	38	280
2010/11	11	-92	67	105	-42	-10	1	75	118	40	273
2011/12	12	-94	69	109	-43	-10	-2	74	124	48	287
2012/13	13	-95	68	111	-43	-11	-5	53	140	62	293
2013/14	14	-97	67	114	-42	-11	-9	48	147	74	305
2014/15	17	-98	69	117	-35	-11	-11	60	152	87	347

Source: PB Associates, using Table 3.8 from Powerlink's APR 2006 and Table 4.6 from APR 2005, and specific advice from Powerlink on the tweed area demand.

Key observations:

- The medium economic growth 10% PoE forecast for 2007/08 increased by 255 MW (or 2.9%) from 8,936 MW to 9,191 MW between the publication of the 2005 and 2006 APRs.
- The demand in the zones supplying South East Queensland (Moreton North, Moreton South and Gold Coast) increased by more than the net change, (i.e. 271MW compared with 255MW).
- The net change in the other zones is small; however there is wide variation from one zone to another.
- The large variations in Table 4.3 and Table 4.4 may be driven by underlying changes in zone based demand or the timing of the demand, since these are coincident and implicitly include geographical diversity.

4.1.2 Application of Demand Forecasts for Planning Purposes

For the purposes of transmission planning, all projected demands are inclusive of the Tweed Shire demand which, by definition is now captured in the NSW demand forecasts, but is maintained in the zone of Gold Coast because the configuration of the network has not actually changed.

Powerlink's transmission network, and the power system in general, is characterised by the geography of Queensland. The network is very long and narrow, effectively stretching 1700 km from Cairns in the Far North to the NSW border in the south. Generation plant, and the inherent mix of capacities and fuel types, is also dispersed widely across the region. The distances involved introduce a more significant dimension of diversity to the operation of this network.

Powerlink must plan and design the transmission network to meet demand forecasts for all feasible conditions. In order to do this, and given that peak electricity demand is highly sensitive to ambient temperature, it disaggregates the network into areas and zones which are more discrete. Quite often, and given the topography of the network and the nature of the demand[18], the peak demand in a certain area is higher than that which occurs at the time of the relevant regions maximum demand. The network must be designed with these local conditions in mind, as well as for the coincident peak demand.

Diversity factors are used to indicate the differences between a zone or an areas peak demand compared with that experienced during the coincident state peak demand conditions. Powerlink's diversity factors are defined as the (long run average) ratio of the zone peak demand to the zone demand at time of the Queensland region peak demand, and these figures are published and updated annually by Powerlink in each APR.

To represent the application of diversity factors (as sourced from each years APR), Table 4.5 and Table 4.6 show the coincident peak demand, the diversity factor and the non-coincident peak for the 2007/08 50% PoE and 10% PoE conditions, respectively. The non-coincident peak demand derived from the diversity factors is an estimate only, based on historical trends and projections of future needs.

Table 4.5: Changes in the 2007/08 medium growth scenario 50% PoE peak summer demand between APR 2005 and APR 2006 (MW).

Zone	2005 Forecast of 2007/08 Medium 50% PoE			2006 Forecast of 2007/08 Medium 50% PoE			Change in coincident	Change in non-coincident
	coincident peak	Diversity factor	non-coincident peak	coincident peak	Diversity factor	non-coincident peak		
Far North	327	1.065	348	334	1.06	354	7	6
Ross	562	1.100	618	474	1.30	616	-88	-2
North	379	1.180	447	421	1.14	480	42	33
Central West	532	1.080	575	611	1.07	654	79	79
Gladstone	1,263	1.010	1,276	1,196	1.03	1,232	-67	-44
Wide bay	262	1.120	293	252	1.13	285	-10	-9
South West	404	1.035	418	408	1.06	432	4	14
Moreton North	1,667	1.004	1,674	1,708	1.01	1,725	41	51
Moreton South	2,360	1.008	2,379	2,442	1.01	2,466	82	88
Gold Coast	856	1.025	877	868	1.01	877	12	0
Total	8,612	1.034	8,905	8,714	1.047	9,121	102	216

Source: PB Associates

The summation of the zone based non-coincident peak demands is a theoretical number and represents the demand that may appear in Queensland if the worst case conditions were experienced across the entire system at the same time. The changes in non-coincident demand in the last column of Table 4.5 and Table 4.6 indicate the effective change in demand between the 2005 and 2006 APRs, without the secondary influence introduced by diversity factors.

Two key observations are that:

- the diversity factors in the Ross, North, Wide Bay and South West zones are all relatively high, indicating that there is considerable variation in the timing of the peak demand in these areas compared with that of the system peak, and

18 The amount of residential, commercial and industrial load within a zone will influence the demand profile.

- the largest increases in the underlying demand, as indicated by changes in the non-coincident zone peak demands, between the 2005 and 2006 APR occur in the Central West, Moreton South and Moreton North zones.

Table 4.6: Changes in the Queensland (coincident) peak summer demand for 2007/08 for the medium growth scenario and 10% PoE conditions between APR 2005 and APR 2006 (MW).

Zone	2005 Forecast of 2007/08 Medium 10% PoE			2006 Forecast of 2007/08 Medium 10% PoE			Change in coincident	Estimate of change in non-coincident[1]
	coincident peak	Diversity factor[1]	Est. non-coincident peak	coincident peak	Diversity factor[1]	Est. non-coincident peak		
Far North	337	1.065	359	346	1.06	367	9	8
Ross	578	1.100	636	490	1.30	637	-88	1
North	390	1.180	460	435	1.14	496	45	36
Central West	548	1.080	592	632	1.07	676	84	84
Gladstone	1,300	1.010	1313	1,237	1.03	1274	-63	-39
Wide bay	269	1.120	301	260	1.13	294	-9	-7
South West	416	1.035	431	422	1.06	447	6	17
Moreton North	1,741	1.004	1748	1,827	1.01	1845	86	97
Moreton South	2,464	1.008	2484	2,613	1.01	2639	149	155
Gold Coast	893	1.025	915	929	1.01	938	36	23
Total	8,936	1.034	9,239	9,191	1.046	9,614	255	375

Note 1: The diversity factors used are those applicable for the 50% PoE conditions. Theoretically, these should not be used to adjust the coincident peak demands to non-coincident peak demands for the 10% PoE conditions. The appropriate temperature sensitivity should be applied to the non-coincident 50% PoE zone peaks to arrive at the non-coincident 10% PoE zone peaks. For the purposes of our presentation we therefore highlight that the non-coincident 10% PoE demands are estimates only.

Source: PB Associates

Powerlink used changes in the coincident peak summer demand forecasts on a zone by zone basis to provided insight into areas of their network where the greatest change in forecast may have impacts. As such the detailed review was restricted to Powerlink's main grid interconnections:

- North Queensland to Far North Queensland (NQ-FNQ);
- South West Queensland to South East Queensland (SWQ-SEQ);
- South East Queensland to Gold Coast/Tweed (SEQ-GC)
- Central Queensland to North Queensland (CQ-NQ); and
- Central Queensland to Southern Queensland (CQ-SQ).

The review of these grid sections is dependant on the following areas:

- South East Queensland, comprised of the Moreton North, Moreton South and Gold Coast/Tweed zones;
- South Queensland, comprised of the Moreton North, Moreton South, Gold Coast/Tweed, Wide Bay and South West zones;

- Gold Coast/Tweed, comprised of the single zone of Gold Coast/Tweed;
- North Queensland, comprised of Far North, Ross and North zones; and
- Far North Queensland, comprised of the single zone of Far North.

It is noted that the zones captured by Powerlink's detailed review account for the majority (approximately 90%) of the increase in the medium growth scenario 10% PoE non-coincident forecasts between the 2005 and 2006 APRs.

4.1.3 Powerlink Implementation of Updated Demand Forecasts

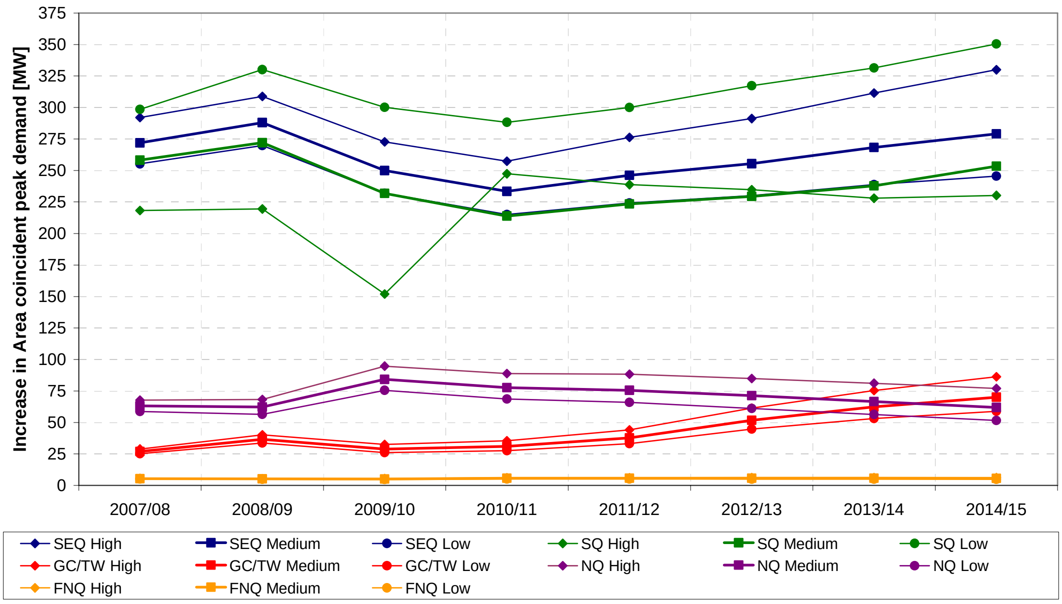
When undertaking its detailed assessment of the increased demand forecasts, Powerlink implemented updated demands into its transmission planning forecasts in accordance with Table 4.7. The original area based coincident peak demands are in Appendix J.

Table 4.7: Changes in the area based coincident peak summer demand between APR 2005 and APR 2006 - 10%PoE conditions (MW)

		2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
SEQ	High	292	309	273	257	276	291	311	330
	Medium	272	288	250	233	246	255	268	279
	Low	255	270	232	215	224	230	239	246
SQ	High	218	220	152	247	239	235	228	230
	Medium	258	272	232	214	223	230	238	253
	Low	299	330	300	288	300	317	331	350
GC/TW	High	29	40	33	35	44	61	75	86
	Medium	27	37	29	31	38	52	62	70
	Low	25	34	26	28	33	45	53	59
NQ	High	68	68	95	89	88	85	81	77
	Medium	63	62	84	78	75	71	67	62
	Low	59	56	76	69	66	61	56	52
FNQ	High	6	5	5	6	6	6	6	6
	Medium	5	5	5	6	6	6	6	6
	Low	5	5	5	5	5	5	5	5

The changes in Area based coincident peak demand are presented in Figure 4-1.

Figure 4-1: Changes in Area based coincident peak demand - 10%PoE conditions



Key observations from Figure 4-1:

- Inconsistent characteristics associated with the 'SQ High' trace, which differ considerably from the 'SQ Medium', the 'SQ Low' and the 'SEQ High' traces. Of particular note is that the 'SQ High' is the only one lower than its 'SQ Medium' and 'SQ Low' versions.
- Significant increases in SEQ and NQ per annum between 2007/08 and 2014/15 for all growth scenarios;
- Large increases in SQ and the GC/Tweed; and
- Marginal increases in FNQ.

These changes in demand forecasts are based on an areas coincident peak demand and it may be the case that each zones peak demand does not occur at the same time as the Areas. Effectively, this indicates that there is an intra-zone diversity factor which may be different from the inter-zone diversity factor that applies at the time of the aggregate Queensland peak.

Relevant characteristics of the changes in Area based coincident peak demand are presented in Table 4.8.

Table 4.8: Summary of changes in Area based coincident peak demand - 10%PoE conditions

		Average % increase	Average annual advancement [years][1]
SEQ	High	4.3%	0.67
	Medium	4.4%	1.01
	Low	4.5%	1.66
SQ	High	2.9%	0.47
	Medium	3.6%	0.85
	Low	5.3%	2.02
GC/TW	High	3.8%	0.48
	Medium	3.8%	0.67
	Low	3.8%	0.94
NQ	High	4.7%	1.02
	Medium	4.5%	1.44
	Low	4.4%	2.49
FNQ	High	1.3%	0.25
	Medium	1.3%	0.33
	Low	1.3%	0.51

Note 1, determined by dividing the annual increase in demand [in MW] for a given year between the 2005 and 2006 forecast and dividing this by the annual growth [in MW] in the original 2005 forecasts.

While noting that the need for augmentation is driven by the complex and non-linear interaction of demand forecasts, generation development and network capability, as an example of the interpretation of the figures in Table 4.8, on average, demand and the associated demand driven augmentation projects in:

- SQ under medium growth 10% PoE will be advanced by around 1 year;
- NQ under low growth 10% PoE will be advanced by around 2.5 years; and
- FNQ under medium growth 10% PoE will be advanced by less than half a year.

It is noted that only increases in the 10% PoE demand forecasts were adopted by Powerlink as part of its detailed review. This is on the basis that Powerlink only uses the 10% PoE forecasts when planning the backbone transmission network[19]. Powerlink has confirmed that as part of its processes for planning the backbone of its network during its revenue proposal preparation, the five load growth themes adopted during its probabilistic approach to determine its forecast capex were all based on the 10% PoE Forecasts, as outlined in Table 4.9.

19 This practice is in accordance with its adopted and published planning criteria.

Table 4.9: Forecasts used by Powerlink to determine its probabilistic based Revenue Proposal

Theme Set	Themes	Transmission backbone and bulk supply points to each zone	Intra-zone constraints
Load growth	Low Growth, 50% POE	10% PoE	50% PoE
	Medium Growth, 50% POE	10% PoE	50% PoE
	Medium Growth, 10% POE[1]	10% PoE	50% PoE
	Medium Growth, 50% POE, plus 500 MW prior to 2009/10 and further 500 MW prior to 2010/11	10% PoE	50% PoE
	High Growth, 50% POE	10% PoE	50% PoE

Source: PB Associates

Note: It appears to PB from Powerlink's application of demand forecasts that the only difference between the medium growth, 50% POE and the medium growth, 10% POE scenarios is the generation development assumed by ROAM Consulting.

We note that the application of demand forecasts in this manner was not fully appreciated during our review of Powerlink's original revenue application given the naming convention adopted for the themes and the disconnect[20] between Powerlink's planning criteria and the probabilistic approach adopted for the purposes of its revenue proposal. We originally understood that all of the load growth themes were based exclusively on the 50% PoE conditions, except in the medium growth 10% PoE case. Powerlink has now clarified that it has designed its backbone transmission network and its bulk supply points to a higher level of reliability than that captured in the naming of its load growth themes.

We concur that it is prudent to plan the main transmission grid with a greater focus on a one in ten year scenario rather than a one in two year scenario given the critical nature of the transmission network, but that the sensitivity to this approach needs to be considered[21]. Using a probabilistic scenario based approach to transmission backbone and supply point planning, as adopted by Powerlink as part of its revenue proposal, we would expect TNSPs to determine their capex requirements from use of both the 50% PoE and 10% PoE cases and weight these appropriately. The relevance of this issue with respect to Powerlink's supplementary submission is associated with the application of a least cost planning approach under the N-1 deterministic criteria in association with increasing temperature sensitive peak demand characteristics. As the temperature sensitivity increases, the least cost planning approach is likely to result in more projects being required to cover peak loads of increasingly shorter duration. Hence the economic benefits from projects implemented to resolve constraints that only arise at the peak of the load curve is reduced.

Our consideration of this matter has focused on the appropriateness of the weightings adopted by Powerlink for each load growth theme set, which were basically prepared by ROAM Consulting. It may be that ROAM Consulting did not fully appreciate the subtlety of the application of the 10% PoE demand forecasts when proposing the appropriate weightings for each theme set given the timeframes in which they were prepared and ROAM Consulting's lack of involvement in the detailed transmission development planning. In our opinion there may be some scope for reviewing the relative likelihood of the five load growth themes used. Nevertheless, we consider that given Powerlink's exclusive adoption of the 10% PoE forecasts for backbone and supply point transmission planning without any sensitivity to the most probable 50% conditions, any review of the

[20] This disconnect is related to the lack of explicit detail within the planning criteria on the use of economic growth scenarios in conjunction with the temperature related forecasts, as applied by Powerlink in its Revenue Proposal.

[21] In respect of this sensitivity, we note that the updated medium economic growth 10% PoE forecast for 2007/08 is 1.3% higher than that for the high economic growth 50% PoE case (this appears to be the first year this is the case) and that it is also 5.5% higher than the medium economic growth 50% PoE forecast for 2007/08. This is directly attributable to the increased air conditioning demand in Queensland.

applicable weightings assigned to the theme sets is likely to have only a second order impact on the overall capex sought over the 2007-2012 regulatory period. On this basis we do not recommend any further review of the applicable theme set probabilities.

4.2 TIMING ADJUSTMENTS CAUSED BY UPATED DEMAND FORECASTS

Powerlink has undertaken a detailed review of the timing of its load-growth sensitive projects based on its three most critical grid sections, as discussed in section 4.1.2. The network development review process replicated that undertaken for the original revenue proposal, but due to time constraints the following areas were not reviewed in the previous level of detail:

- The timing and scope of projects associated with joint planning and connections were not systematically revised. Given that projects of this nature are primarily driven by 50% PoE forecasts and there has not been as significant an increase in these forecasts when compared to the 10% PoE forecasts, Powerlink considered there would be no material impact on the capex required for this class of project. Treatment of 275/132/110 kV transformation was based on high level utilisation rates, where a new transformer was advanced into the regulatory period, and at the same time other transformer timings were adjusted.

- The timing or scope of projects driven by voltage stability or voltage control limitations was not revised, unless the constraint was also associated with a thermal limitation, which was used to inform Powerlink's decision on any advancement. The technical analysis associated with this class of constraints is complicated and time consuming. Powerlink has adopted the approach that connection point power factors will be maintained at the prescribed National Electricity Rules levels given the new peak demand forecasts and that any change in timing would be related to advanced thermal limits being reached. No projects have been advanced ahead of their thermal limitation timings based on voltage stability criteria as part of the demand forecast review.

- The timing or scope of the generation planting program was not revised due to time constraints. In theory, as demand forecasts increase, the need for and timing of new generation would also be advanced. Depending on the exact location of such generators, they may assist or promote transmission constraints and therefore the need for augmentation. Powerlink adopted a pragmatic approach of locating its 'slack' generator in the constrained regions resulting in transmission plans that were of a conservative nature.

Powerlink's analysis included a review of the timing of critical projects under all 40 of the generation based probabilistic scenarios (even though the revision of the PNG gas pipeline project probability was reduced to 0% and therefore 20 of the 40 scenarios were eliminated). Specifically, the outcome of the review has been an adjustment in the timing of projects – there was no change in the scope of any project as a consequence of the revised load forecasts. There are cases where expenditure is found to be advanced into the 2007-2012 regulatory period. As part of its process, Powerlink also used the detailed results of its initial transmission development plans to assist in determining the optimal planning outcome.

Powerlink's review also involved a full repeat of the NPV analysis of alternatives considered to resolve network constraints. The benefits of larger, strategic investment options were compared with smaller incremental investment options using this NPV analysis.

As a result of Powerlink's review of its scenario based transmission development plans, 28 separate projects have had their timings adjusted[22]. Two of these projects are related to the acquisition of easements for construction projects and the remaining 26 are augmentation projects. Three of the augmentation projects are new and have been advanced sufficiently to require expenditure within the 2007-12 regulatory period.

A complete list of the 28 projects is contained in Table 4.10, along with changes introduced as a result of the revised demand forecasts. In summary, there are 9 projects associated with supply into South East Queensland (SEQ), 2 projects associated with supply from Central Queensland to North Queensland (NQ), 9 projects associated with supply to Southern Queensland (SQ) and a further 8 associated with 275/110 kV transformer capacity in South East Queensland (SEQ Tx).

Table 4.11 summarises the cost impacts identified by Powerlink on a project by project basis as a result of the updated demand forecasts. For simplicity, it only contains the changes assuming the median project timing, which is consistent with Powerlink's published Information Templates. Table 4.11 has been informed by detailed annual expenditure as included in Appendix L. For the avoidance of doubt, the actual increase in Powerlink's capex as a result of the updated demand forecasts is $129 million and this differs from the summated value in Table 4.11 of $123 million because it has been determined on a more accurate basis using the full accumulation model. The full accumulation model accounts for the actual commissioning date per scenario rather than the median timing.

[22] This is out of a total of 129 augmentation projects and 70 easement projects originally proposed by Powerlink, which had timings sensitive to the 40 generation development scenarios.

Table 4.10: Identification and number of scenarios for projects that have had their timing modified due to the updated demand forecasts

Project Number	Project Name	2005 Forecasts				2006 Forecasts				Same	Advanced	Deferred	Removed	Introduced	Grid Section
		Low	Med.	High	Total	Low	Med.	High	Total						
CP.00369	Establish Halys 275kV Substation and Braemar to Halys 500kV DCST operating at 275kV	0	15	8	**23**	2	6	4	**12**	7	3	0	13	2	SEQ
CP.00775/B	Braemar to Halys 500kV DCST line operating at 275kV (Halys already established)	0	1	0	**1**	0	16	4	**20**	0	1	0	0	19	SEQ
CP.00369/A	Establish Halys 275kV Substation and Calvale to Halys 2nd 275kV DCST 1st stage (single circuit strung)	0	3	0	**3**	0	12	4	**16**	0	1	0	2	15	SQ
CP.00369/B	Establish Halys 275kV Substation and Calvale to Halys 2nd 275kV DCST 1st stage (both circuit strung)	0	2	0	**2**	0	6	0	**6**	0	2	0	0	4	SQ
CP.01512/A	Strathmore-Ross 275kV DCST - both circuits strung (paralleled operation)	0	4	4	**8**	0	4	4	**8**	0	8	0	0	0	NQ
CP.01540	Middle Ridge 1st Transformer upgrade to 1500MVA	0	10	8	**18**	2	10	3	**15**	0	1	6	11	8	SEQ
CP.01544	Southpine 350MVAr SVC	0	14	8	**22**	0	9	8	**17**	17	0	0	5	0	SEQ
CP.01615	Auburn River Switching Station (2 switched circuits)	0	9	1	**10**	2	1	4	**7**	0	1	0	9	6	SQ
CP.01615/D	Auburn River Switching Station (3 switched circuits)	0	2	0	**2**	0	1	0	**1**	0	0	0	2	1	SQ
CP.01615/C	Auburn River Switching Station (4 switched circuits)	0	0	0	**0**	0	1	0	**1**	0	0	0	0	1	SQ
CP.01836	Gin Gin 250MVAr SVC	0	3	1	**4**	1	0	4	**5**	0	0	0	4	5	SQ
CP.01841	Millmerran Series Line Reactors	0	10	8	**18**	2	11	3	**16**	0	1	6	11	9	SEQ
CP.01875	Halys to Blackwall 500kV operating at 275kV	0	4	8	**12**	0	12	8	**20**	7	5	0	0	8	SEQ
CP.01833/A	Easement Acquisition for Calvale to Halys 2nd 275kV Double Circuit Line (TE)	0	6	2	**8**	1	18	3	**22**	1	5	0	2	16	SQ
CP.01833/B	Easement Acquisition for Calvale to Halys 2nd 275kV Double Circuit Line (compensation)	0	6	2	**8**	1	18	3	**22**	1	5	0	2	16	SQ
CP.01722/B	Calvale to Halys 2nd 275kV DCST 1st stage (single circuit strung - Halys established)	0	0	1	**1**	0	0	0	**0**	0	0	0	1	0	SQ
CP.01792	Karana Double Tee from Upper Kedron	0	24	8	**32**	0	24	8	**32**	8	24	0	0	0	SEQ
CP.01594	Abermain 2nd 275/110kV 300MVA Transformer	0	0	8	**8**	0	24	8	**32**	0	8	0	0	24	SEQ Tx
CP.01839	Cedar Creek 275/110kV Substation Establishment	0	0	8	**8**	0	0	8	**8**	0	8	0	0	0	SEQ Tx
CP.01595	Goodna 2nd 275/110kV 375MVA Transformer	0	0	8	**8**	0	0	8	**8**	0	8	0	0	0	SEQ Tx
CP.01195/A	Larapinta 275kV Substation Establishment	8	24	8	**40**	8	24	8	**40**	16	24	0	0	0	SEQ Tx
CP.01528/A	Molendinar 3rd 275/110kV 300MVA transformer	8	24	8	**40**	8	24	8	**40**	32	8	0	0	0	SEQ Tx

Project Number	Project Name	2005 Forecasts				2006 Forecasts				Same	Advanced	Deferred	Removed	Introduced	Grid Section
		Low	Med.	High	Total	Low	Med.	High	Total						
CP.00390	Rocklea 275kV bus & 3rd 300MVA 275/110kV transformer	0	24	8	**32**	0	24	8	**32**	8	24	0	0	0	SEQ Tx
CP.01844	Southpine Transformer Augmentation and 110kV Split Bus	8	24	8	**40**	8	24	8	**40**		40	0	0	0	SEQ Tx
CP.01684	Swanbank A 2nd 275/110kV Transformer Connection	0	24	8	**32**	8	24	8	**40**	8	24	0	0	8	SEQ Tx
CP.01877/B	Halys to Blackwall 500kV operating at 500kV	0	0	0	**0**	0	0	2	**2**	0	0	0	0	2	SEQ
CP.01959	Braemar to Halys operating at 500kV	0	0	0	**0**	0	0	2	**2**	0	0	0	0	2	SEQ
CP.01156/B	Stanwell to Broadsound 2nd 275 Circuit	0	0	0	**0**	0	4	0	**4**	0	0	0	0	4	NQ

Table 4.10 Notes:

- Information presented accounts for the sequence of adjustments made by Powerlink, specifically the CQ-SQ review and the PNG theme set review.
- Each table item is a count of the number of scenarios. There are 8 high growth, 24 medium growth and 8 low growth scenarios.
- Same, indicates the number of scenarios where the timing has not changed as a result of the updated forecasts.
- Advanced, indicates the number of scenarios where the timing has been advanced as a result of the updated forecasts.
- Deferred, indicates the number of scenarios where the timing has been deferred as a result of the updated forecasts.
- Removed, indicates the number of scenarios where the project is no longer required in the 2007-2012 regulatory period as a result of the updated forecasts.
- Introduced, indicates the number of scenarios where the project is now required in the 2007-2012 regulatory period as a result of the updated forecasts.
- Grey shaded Total items indicate the number of scenarios where the count of the number of scenarios the project is identified in has reduced as a result of the updated forecasts.
- Grey shaded project names indicate projects that are new and are now forecast to require expenditure within the 2007-2012 regulatory period.

Table 4.11: Approximate quantification of increased capex requirements due to the updated demand forecasts

Project Number	Project Name	2005 demand Forecasts			2006 demand Forecasts			Increase in probability [%]	Advancement in median timing [years]	Capex Increase [$000's]
		Median commiss. date	Probability [%]	Probability weighted capex in Reg. Period [$000's]	Median commiss. date	Probability [%]	Probability weighted capex in Reg. Period [$000's]			
CP.01875	Halys to Blackwall 500kV operating at 275kV	31/10/2012	29.52	58,807	31/10/2011	68.97	142,211	39.44	1	$83,404
CP.00369/A	Establish Halys 275kV Substation and Calvale to Halys 2nd 275kV DCST 1st stage (single circuit strung)	31/10/2011	2.80	6,702	31/10/2008	12.53	26,605	9.73	3	$19,903
CP.00775/B	Braemar to Halys 500kV DCST line operating at 275kV (Halys already established)	31/10/2011	2.80	3,827	31/10/2011	13.28	18,123	10.48	0	$14,297
CP.00390	Rocklea 275kV bus & 3rd 300MVA 275/110kV transformer	30/09/2013	76.07	3,415	30/09/2012	76.07	15,677	-	1	$12,262
CP.01156/B	Stanwell to Broadsound 2nd 275 Circuit	-	-	-	31/08/2012	40.94	6,214	new	new	$6,214
CP.01836	Gin Gin 250MVAr SVC	31/10/2009	2.09	575	31/08/2009	16.44	4,526	14.35	0	$3,950
CP.01615	Auburn River Switching Station (2 switched circuits)	31/10/2009	5.23	1,002	30/06/2009	22.79	4,355	17.56	0	$3,353
CP.00369/B	Establish Halys 275kV Substation and Calvale to Halys 2nd 275kV DCST 1st stage (both circuit strung)	31/10/2009	0.00	0	31/10/2008	0.75	1,837	0.75	1	$1,837
CP.01877/B	Halys to Blackwall 500kV operating at 500kV	-	-	-	31/10/2011	1.01	1,829	new	new	$1,829
CP.01839	Cedar Creek 275/110kV Substation Establishment	31/08/2013	7.28	423	31/08/2012	7.28	1,848	-	1	$1,425
CP.01959	Braemar to Halys operating at 500kV	-	-	-	31/10/2011	1.01	1,134	new	new	$1,134
CP.01594	Abermain 2nd 275/110kV 300MVA Transformer	30/09/2011	7.28	749	30/09/2013	76.07	1,717	68.79	-2	$968
CP.01792	Karana Double Tee from Upper Kedron	30/09/2013	76.07	156	30/09/2012	76.07	1,026	-	1	$870
CP.01595	Goodna 2nd 275/110kV 375MVA Transformer	31/10/2013	7.28	176	31/10/2011	7.28	856	-	2	$680
CP.01684	Swanbank A 2nd 275/110kV Transformer Connection	31/07/2012	76.07	1,690	31/07/2010	100.00	2,200	23.93	2	$510
CP.01615/D	Auburn River Switching Station (3 switched circuits)	31/10/2010	0.75	106	31/07/2010	2.80	396	2.06	0	$291
CP.01833/B	Easement Acquisition for Calvale to Halys 2nd 275kV Double Circuit Line (compensation)	30/10/2010	3.55	142	30/10/2009	12.67	384	9.12	1	$243
CP.01540	Middle Ridge 1st Transformer upgrade to 1500MVA	31/07/2010	24.48	1,631	31/07/2011	27.35	1,826	2.87	-1	$194
CP.01833/A	Easement Acquisition for Calvale to Halys 2nd 275kV Double Circuit Line (TE)	30/10/2009	3.55	161	30/10/2008	12.67	263	9.12	1	$102

Project Number	Project Name	2005 demand Forecasts			2006 demand Forecasts			Increase in probability [%]	Advancement in median timing [years]	Capex Increase [$000's]
		Median commiss. date	Probability [%]	Probability weighted capex in Reg. Period [$000's]	Median commiss. date	Probability [%]	Probability weighted capex in Reg. Period [$000's]			
CP.01615/C	Auburn River Switching Station (4 switched circuits)		0	0	31/08/2012	0	0	-	removed	$0
CP.01528/A	Molendinar 3rd 275/110kV 300MVA transformer	31/03/2010	100.00	19,526	31/03/2010	100.00	19,526	-	0	$0
CP.01195/A	Larapinta 275kV Substation Establishment	31/10/2010	100.00	59,910	31/10/2009	100.00	59,476	-	1	-$434
CP.01512/A	Strathmore-Ross 275kV DCST - both circuits strung (paralleled operation)	31/10/2010	47.21	69,315	31/10/2009	47.21	68,739	-	1	-$577
CP.01841	Millmerran Series Line Reactors	31/07/2010	24.48	1,586	31/07/2011	27.35	987	2.87	-1	-$598
CP.01722/B	Calvale to Halys 2nd 275kV DCST 1st stage (single circuit strung - Halys established)	31/10/2010	0.61	1,089		0	0	-0.61	removed	-$1,089
CP.01844	Southpine Transformer Augmentation and 110kV Split Bus	31/08/2009	100.00	18,209	31/08/2008	100.00	14,023	-	1	-$4,185
CP.01544	Southpine 350MVAr SVC	31/07/2012	69.34	17,751	31/07/2011	29.34	7,465	-40.00	1	-$10,286
CP.00369	Establish Halys 275kV Substation and Braemar to Halys 500kV DCST operating at 275kV	31/10/2011	73.27	124,968	31/10/2011	65.67	112,010	-7.60	0	-$12,958
TOTAL ($000's, real, 06/07):				**317,165**			**515,253**			**123,339**

Table 4.11 Notes:

- Information presented accounts for the sequence of adjustments made by Powerlink, specifically the CQ-SQ review, cost increases and the PNG theme set review.
- For the purposes of this example, the quantification of the impact has been based on the median timing of projects and is therefore an estimate only. To determine the actual increases, Powerlink has applied its accumulation program across all forty scenarios given the explicit network development plans determined. This approach is consistent with the calculation of the initial revenue proposal and this review has not included a detailed assessment of the accuracy or validity of this process.
- Determination of real expenditure profile in this example is based in simplified CPI de-escalation at 2.91% per annum.
- Summarised from detailed annual expenditure tables as presented in Appendix L.

Table 4.12 provides a direct comparison of the changes in the capex sought by Powerlink using its detailed probabilistic accumulation model in its original revenue proposal and the capex sought using the simplified and more deterministic median commissioning dates process in its supplementary revenue proposal.

Table 4.12: Impact of 2006 load forecast review on total forecast capital expenditure

$m real 06/07	2007/08	2008/09	2009/10	2010/11	2011/12	TOTAL
Change in total capex – load forecasts, probabilistic detail	55.12	54.42	(57.27)	50.33	26.40	129.00
Change in total capex – load forecasts, deterministic example (Table 4.11)	56.37	78.61	(77.96)	102.32	(36.01)	123.34

It is noted that while the project adjustments in Table 4.12 are based on median project timings, which provide a reasonable insight into the change in total required capex over the coming regulatory period, the annual expenditure profile is very different from that determined through Powerlink's detailed accumulation process – especially in the final two years of the period where the impacts of the increased demand forecasts are more sensitive. This result highlights the large variation in capex across each of the 40 scenarios modelled.

4.3 NEED FOR ADVANCEMENT

One of the key observations from our review of Powerlink's original capex forecast was the direct relationship between demand growth and augmentation capex. The probability weighted capex did not vary as significantly within each of the five load growth themes as it did within the other theme sets of generation from PNG gas, carbon tax and QNI upgrades, but there was considerable variation across the five themes[23]. Effectively using the average of the deterministic forecast capex within each scenario of a theme set, it was identified that under the high economic growth 50% PoE conditions, Powerlink's capex would be 1.8 times greater than under the low economic growth 50% PoE conditions (i.e. $3,182million compared with $1,772 million). In our opinion, the use of a wide selection of forecast conditions and the appropriate selection of theme weightings provided Powerlink with a reasonable probability weighted capex forecast to base its revenue proposal on.

From our previous review, the sensitivity of capex needs to demand forecast was clearly established and the need for increased capex requirements under higher demand conditions was obvious. Given the increased demand forecasts included in Powerlink's APR 2006, and without questioning the accuracy, validity or reasonableness of the increases, it can be concluded that the need for advanced timing for transmission development is justified. Our role as part of this review has been to test the appropriateness of the method Powerlink used to quantify the increased forecast capex assuming the increases in demand forecasts were accepted.

23 Refer section 4.4.3.4 and Table 4.15 of PB Associates Review of Capital Expenditure, Operating and maintenance Expenditure and Service Standards, December 2006.

4.4 DETAILED PROJECT REVIEWS

Our review of Powerlink's proposed forecast capex increases resulting from the updated 2006 demand forecasts has been informed by a detailed review of 3 projects that Powerlink proposed to advance in timing.

Our selection of projects was based on the increased probabilities presented by Powerlink in its Supplementary Revenue Proposal – Attachment, 2006 Demand Forecasts:

- CP.01875 - Halys to Blackwall 500kV double circuit operating at 275kV
- CP.01156/B - Stanwell-Broadsound second 275kV circuit
- CP.00369/A - Establish Halys 275kV substation and Calvale-Halys 2nd DC (1st Stage, single circuit strung)

Powerlink also advised of specific adjustments to Strathmore-Ross project, which was advanced by one year in each of the eight scenarios in the initial application. However, as part our review of the demand forecast impacts, we have not reviewed this information in detail, nor made specific recommendations in respect of this project.

4.4.1 CP.01875 - Halys to Blackwall 500kV double circuit operating at 275 kV

The scope of this project includes the construction of approximately 153 km of 500 kV double circuit quad conductor transmission line from Halys to Blackwall[24] via Springdale, initially operating at 275 kV and switched by four new circuit breakers at each end to allow the new lines to be switched, monitored and protected from faults. This project is dependant on the prior establishment of 275 kV switching at Halys (CP.00369).

In Powerlink's original revenue application, this project was identified in 12 of the 40 scenarios, with a cumulative probability of 19%, and an estimated capital cost within the regulatory review period of $193.22 million (real, 06/07)[25]. The timing of the project was identified as either 31/10/2010 (high growth) or 31/10/2013 (medium growth).

This project is the single most critical project impacted by the increased 2006 demand forecasts. The increased probability weighted capex associated with this project is around $83 million[26] out of the $123 million, or 68%. The modified timing and probability of this project that supports this increase is presented in Table 4.13.

24 This is effectively from the South West zone into Moreton North.
25 Assuming the project's median commissioning date.
26 Ibid.

Table 4.13: Changes in timing and probability of CP.01875 as a result of updated demand forecasts

Scenario	2005 forecasts[1]		2006 Forecasts		Scenario	2005 forecasts		2006 Forecasts	
	Timing	Probability	Timing	Probability[2]		Timing	Probability	Timing	Probability
1					21	31/10/13	3.79%	31/10/12	7.10%
2					22	31/10/13	0.50%	31/10/12	0.93%
3					23				
4					24			31/10/12	0.00%
5					25				
6					26				
7					27				
8					28				
9			31/10/11	20.38%	29	31/10/13	1.69%	31/10/13	3.18%
10			31/10/11	2.80%	30			31/10/12	0.56%
11					31				
12					32				
13	31/10/13	5.88%	31/10/11	11.03%	33	31/10/11	1.99%	31/10/11	4.04%
14			31/10/11	1.68%	34	31/10/10	0.30%	31/10/10	0.61%
15					35	31/10/11	1.99%	31/10/11	0.00%
16					36	31/10/12	0.30%	31/10/10	0.00%
17			31/10/13	12.52%	37	31/10/11	1.10%	31/10/11	2.22%
18			31/10/12	1.50%	38	31/10/10	0.20%	31/10/10	0.40%
19					39	31/10/11	1.20%	31/10/11	0.00%
20			31/10/12	0.00%	40	31/10/13	0.20%	31/10/10	0.00%
Summated probabilities:							19.14%		68.97%
Median Timing:						01/05/12		31/10/11	

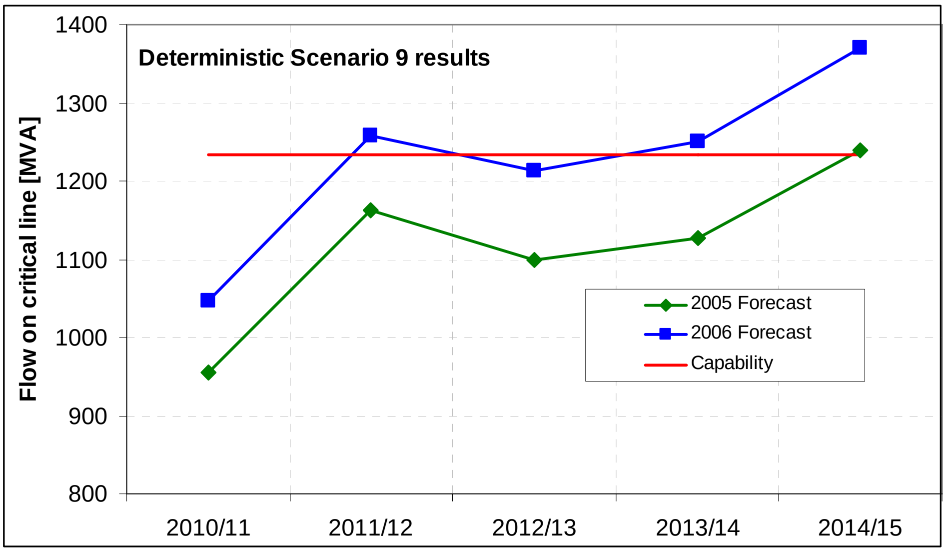
Note 1, These probability and timing figures are aligned with Powerlink's original revenue application where the PNG theme set was assigned a probability of 50%. Therefore they do not align with the probabilities presented in Table 4.11, which are presented after the reduction of the PNG theme set probability to 0%.

Note 2, 2006 individual scenario probabilities have been changed due to the removal of the PNG gas theme set.

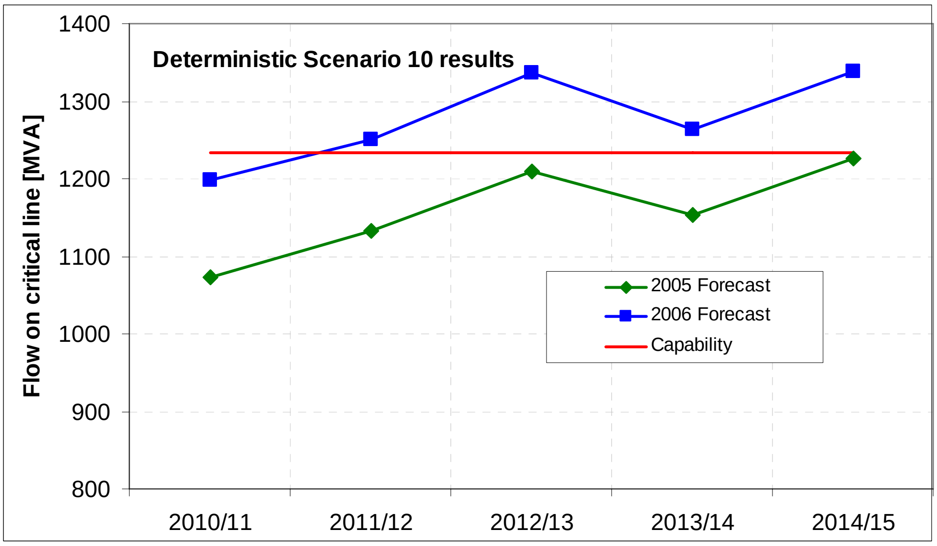
Note 3, Grey shaded cells indicate a scenario in which the timing of the project has been advanced.

To support the advancement of timing associated with this project, Powerlink submitted detailed load flow and thermal constraint analysis data for four scenarios:

- Scenario 9 (20.38%), where the project is advanced from 2014/15 (with no expenditure in the 2007-2012 regulatory period) to 2011/12 as part of a package of works to increase the Tarong limit - as limited by the thermal capacity of the Middle Ridge-Greenbank 275 kV line. The capability of the critical line is 1,234 MVA, and with the 2005 forecast it is loaded to 1,250 MVA in 2014/15 and with the 2006 forecast it is loaded to 1,258 MVA in 2011/12. The theoretical need to advance the project under these new conditions is driven by the slight thermal overload in 2011/12. Powerlink also advised that voltage limitations compounded the thermal constraints but did not provide evidence to substantiate this. Nevertheless it is not clear that the project should necessarily be advanced by three years given that the overload in 2011/12 is marginal and that it disappears the following year, and that there may be other options to address any voltage stability limitations. This is discussed further in the following sections.



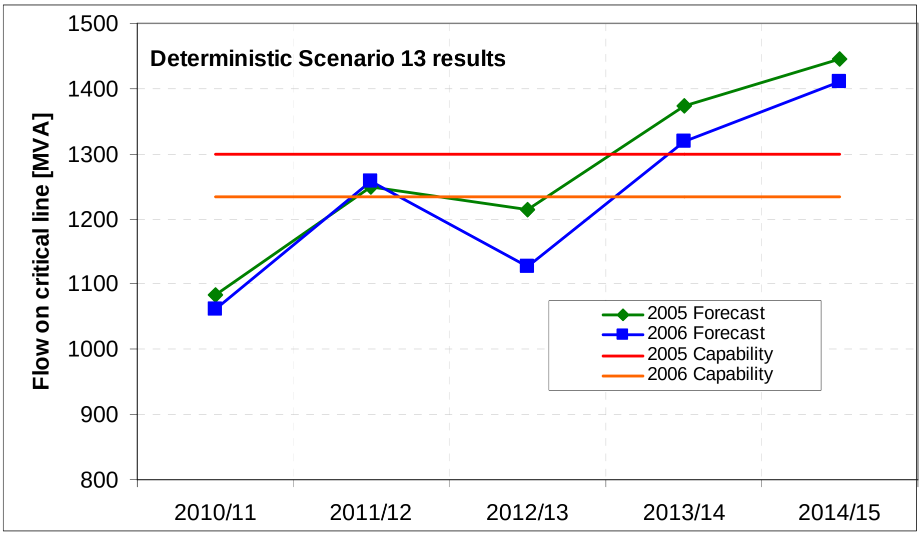
- Scenario 10 (2.80%), where the project is advanced from 2014/15[27] (with no expenditure in the 2007-2012 regulatory period) to 2011/12 as part of a package of works to increase the Tarong limit - as limited by a combination of voltage stability limits and the thermal capacity of the Middle Ridge-Greenbank 275 kV line. The capability of the critical line is 1,234 MVA, and with the 2005 forecast it is loaded to 1,227 MVA in 2014/15 and with the 2006 forecast it is loaded to 1,250 MVA in 2011/12. The need to advance the project three years is clear.



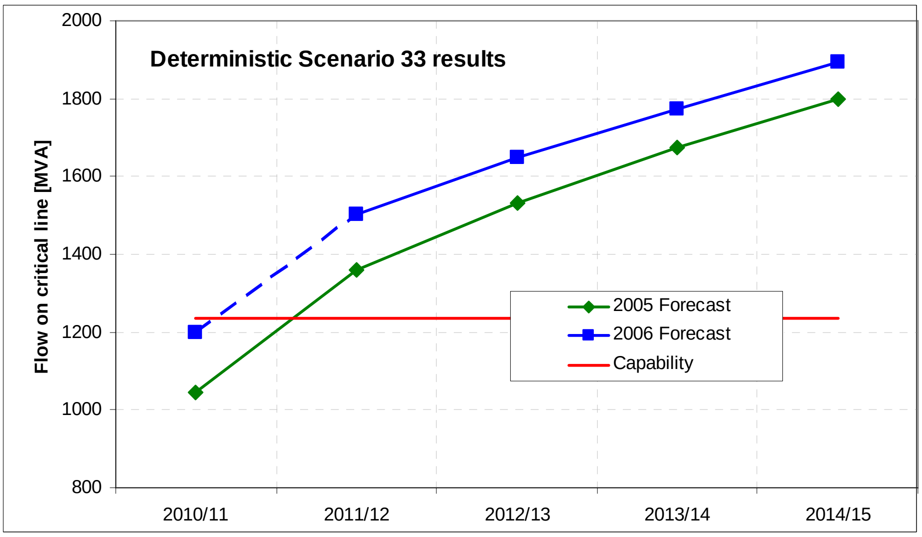
- Scenario 13 (11.03%), where the project is advanced from 2013/14 to 2011/12 as part of a package of works to increase the Tarong limit - as predominantly limited by the thermal capacity of the Middle Ridge 330/275 kV transformer or the Middle Ridge-Greenbank 275 kV line. Powerlink also advised that the thermal constraints were compounded by voltage stability limits, but provided

27 While the thermal limitation does not occur in 2014/15, consideration of voltage stability limitations dictate that the 500 kV lines would need to be built by 2014/15.

no evidence to quantify or substantiate this. The capability of the critical transformer and line is 1,300 MVA and 1,234 MVA, respectively, and with the 2005 forecast the transformer is loaded to 1,373 MVA in 2013/14 and with the 2006 forecast the line is loaded to 1,257MVA in 2011/12. The need to advance the project two years is marginal.



- Scenario 33 (4.04%), where the project timing is still required in 2011/12 irrespective of the change in demand forecasts as part of a package of works to increase the Tarong limit - as limited by the thermal capacity of the Middle Ridge 330/275 kV transformer, the Middle Ridge-Greenbank 275 kV line, or the Middle Ridge-Millmerran 275 kV line. The most critical constraint is on the Middle-Ridge-Greenbank line. The key influence in this scenario is that with the increased 2006 demand forecasts the Calvale to Halys double circuit line (one circuit strung) is constructed in 2008/09, which reinforces the network to ensure the Braemar-Halys project is still timed for 2009/10 and subsequently the Halys-Blackwall project is still timed for 2011/12. The 2006 forecast loading presented in 2010/11 is based on an assumption we have made as the figure was not available from Powerlink's submissions. The timing of works in 2011/12 is reasonable.



An indication of the overall impact of the updated demand forecasts is provided in Table 4.14, assuming the projects median commissioning date.

Table 4.14: Changes in expenditure profile of CP.01875 as a result of updated demand forecasts, assuming median commissioning date. ($,000s)

Forecasts	Median C'issioning date	Prob-ability	2007-08	2008-09	2009-10	2010-11	2011-12	Total Reg. Period	Probability Weighted Total Reg. Period
2006	31/10/2011	68.97%	-	-	18,005	179,582	8,611	206,198	142,211
2005	31/10/2012	29.52%	-	-	-	18,148	181,035	199,183	58,807
Total increase:									+83,40

When considering the efficiency of Powerlink's increased expenditure for this project, we have drawn from the observations from the detailed scenarios analysed. In two of the four scenarios we consider that Powerlink has advanced the timing of the project in a manner that is not efficient or economic. In the case of Scenario 9, we consider that the advancement of three years, while being theoretically based is not a practical outcome. Powerlink's assessment process indicates that the trigger for the project is the 2% thermal overload of the Middle Ridge-Greenbank line for loss of the parallel circuit experienced in 2011/12, which is compounded by voltage stability issues. We consider the need to advance the project three years for this scenario is marginal, and that a one year advancement is more reasonable.

The risk of actually losing load on the basis of the Scenario 9 hypothesis is very low in that (i) the load at risk is very small, (ii) it occurs for a one in ten year peak demand (i.e. 10% PoE condition notwithstanding that Scenario 9 is a representative of a medium 50% PoE scenario), coincident with; (a) the loss of a very new, high reliability transmission line and (b) the unavailability of the largest generator in South East Queensland – Swanbank E, and (c) Wivenhoe operating at only 30% capacity. Furthermore any such overload would only occur for a few hours of the year. In our view, such a risk is comparable with a 1 in 20 year (5% PoE condition) demand scenario, which is outside the bounds of Powerlink's planning criteria, but which is still possible. The need to defer the augmentation is further supported by the overload being eliminated the following year.

In our view a prudent TNSP would not advance such a high cost project (>$200 million) to mitigate such a low risk of loss of load. Furthermore, even if the situation was considered unacceptable in the context of Powerlink's legal obligations, there are a number of lower cost short term alternatives that could be considered (singularly or in combination) over the two year period to further mitigate the risk. These include, but are not necessarily limited to:

- a technical review of the transmission thermal capability to identify any design margin that could be utilised;
- installation of temperature and wind monitoring to provide real time thermal line ratings;
- a negotiated reduction in reliability standards with connected parties for a short duration (i.e. accept some minor and controlled load shedding after the event should the coincidence of the worst case scenario parameters eventuate). Thermal time constants given the low level of potential overload indicate that there will be considerable time to undertake such action without any actual damage to the transmission line;

- demand side management, triggered by failure of Swanbank E;
- alternative considerations of the export of power to NSW via DirectLink;
- refining planning assumptions to assume, for example that Wivenhoe can be dispatched at 200MW instead of 150MW; and/or
- line patrols and visual inspections of the critical circuits to ensure they are in optimal condition prior to the critical summer peak demand.

Given the overload situation is a worst case, multi-contingency scenario and that it would only occur for a few hours, we consider it is more practical and economic to advance the project by one year instead of three.

Without access to Powerlink's full accumulation model, we have estimated the increase in required capex for this project to be around $20 million rather then $83.4 million. This allowance has been determined in accordance with the calculations outlined in Table 4.15 which is focussed on outlining the capex impacts when comparing the proposed timing of 2011/12 for scenario 9 and our recommended timing of 2013/14, and the proposed timing of 2011/12 for scenario 13 and our recommended timing of 2013/14. We have made an additional adjustment to round the $59.1 million reduction for these two scenarios, as determined from Table 4.15, up to $63.4million based in the possibility that inefficient advancement has occurred in other scenarios (in addition to the two considered in detail). This increase has been estimated on the basis that we have only examined three out of thirteen scenarios in which the project was advanced and the changes to the timing of the project in two of these cases has resulted in a reduction in the required capex of over 70%. While the actual amount of this final increase is not well supported analytically, we nevertheless consider our final recommendation for this project to be reasonable as it could also be argued that the project need not be advanced at all based on thermal limitations for the materially influential scenario 9.

Table 4.15: Revised expenditure profile of CP.01875 as a result of updated demand forecasts for two key scenarios. ($000)

Scenario	C'issioning date	Probability	2007-08	2008-09	2009-10	2010-11	2011-12	Total Reg. Period
9	31/10/2011	100%	-	-	18,005	179,582	8,611	206,198
		20.38%	-	-	3,669	36,599	1,755	42,023
	31/10/2013	100%	-	-	-	-	18,005	18,005
		20.38%	-	-	-	-	3,669	3,669
13	31/10/2011	100%	-	-	18,005	179,582	8,611	206,198
		11.03%	-	-	1,986	19,808	950	22,744
	31/10/2013	100%	-	-	-	-	18,005	18,005
		11.03%	-	-	-	-	1,986	1,986
Proposed weighted increase for these two scenarios only[28]								64,767
Recommended weighted increase for these two scenarios only[29]								5,655
Reduction for these two scenarios only								(59,112)

28 This figure has been calculated as the sum of $42,023 for scenario 9 and $22,744 for scenario 13 based on the weighted capex and Powerlink's proposed project timings.

29 This figure has been calculated as the sum of $3,669 for scenario 9 and $1,986 for scenario 13 based on the weighted capex and our recommended project timings.

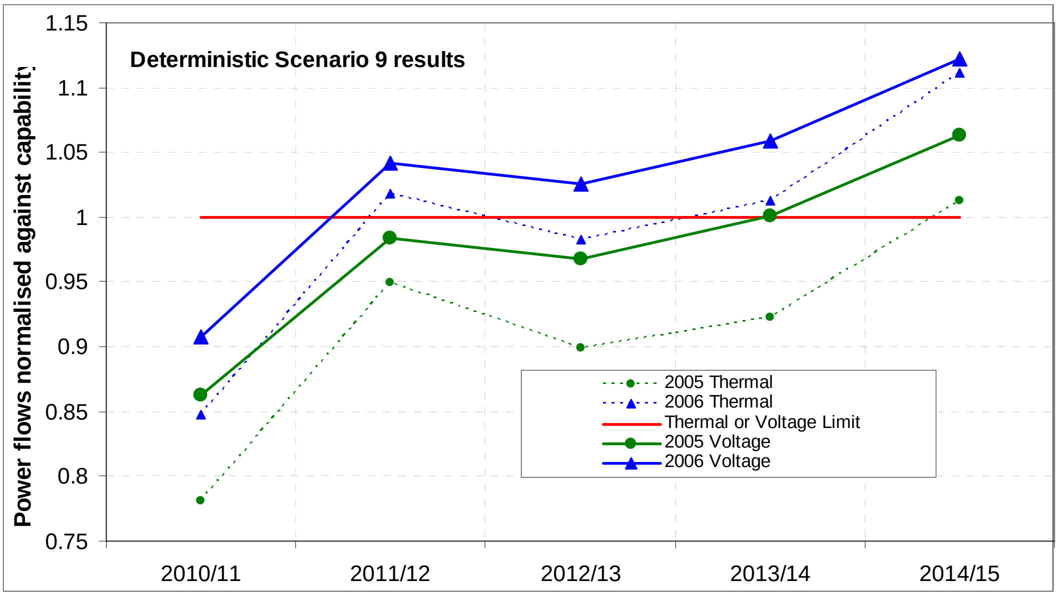
Voltage Stability Considerations

Subsequent to our review of Powerlink's supplementary submission and its considerations and presentation of the thermal limitations regarding supply between SWQ-SEQ, Powerlink has provided new and additional information concerning voltage stability constraints into SEQ that has a material impact on our conclusions and recommendations for this project.

Powerlink had not previously considered the impact of the revised demand forecasts on voltage stability limits given the complexity of the analysis and the time available, as discussed in Section 4.2 of this report.

Powerlink has advised that based on its voltage stability criteria, the voltage stability limit across the Tarong grid section is close to 5,510 MW[30]. While noting that Powerlink has not supported this transfer capability with detailed technical analysis[31], we concur with Powerlink that this voltage stability limit will be exceeded from 2011 for the critical scenario 9 condition. This is shown in Figure 4-2, which shows both the voltage stability and thermal limits normalised against the defined transfer limits[32] for both the 2005 and 2006 forecasts.

Figure 4-2: Transmission constraints into SEQ for Scenario 9



The characteristics of Figure 4-2 are dictated by the forecast retirement of Swanbank B (500MW) in SEQ prior to 2011/12 and the commissioning of Swanbank F (400MW) prior to 2012/13. As an observation, we note that in high demand growth scenarios, additional generation has been planted in SEQ. Given this review is associated with higher growth in this region - there may be further scope to consider the increased likelihood of this new generation occurring in more scenarios. For the purposes of this review however, no changes to the original generation programme have been made.

The key observation from Figure 4-2, is that voltage stability limits are always worse than the thermal limits and in the majority of cases substantially so. Given the updated demand forecasts, the voltage limit will be exceeded by 4.2%, 2.5% and 5.9% in 2011/12, 2012/13 and 2013/14, respectively. We find it somewhat surprising that Powerlink

30 Email dated 08 March 2007, Powerlink to PB Associates.

31 A suite of P-V curves in conjunction with Q-V curves at critical load levels would further support the limit.

32 1234 MVA in the case of the thermal limit, and 5510 MW in the case of the voltage stability limit.

focussed so much attention on the thermal limitations as part of its supplementary submission and ensuing discussions, when it should have been quite clear from work it carried out under the 2005 demand forecasts that the voltage stability limit was far more onerous than the thermal limits (i.e. in 2013/14 the voltage stability limit is marginal and the first to be exceeded, while there is considerable headroom of around 8% when considering the thermal limits alone). Nevertheless, given the latest information it is evident that our proposal to defer the timing of the project to 2013/14 for scenario 9 is not a technically or economically viable option alone.

Without the insight of a detailed technical or economic review of the transmission capability into SEQ under the new demand forecasts (including an optimisation review of both the transmission line augmentation and the substantial reactive planting programme proposed in SEQ), we consider a reasonable lower cost approach to primarily address the voltage stability constraints and secondarily reduce the thermal constraints apparent in 2011/12 is to advance to installation of the South Pine SVC project. We note that the SVC will only have a minor impact (by reducing MVAr flows) with respect to the marginal and temporary thermal overload in 2011/12. As a consequence of the updated demand forecasts, this project (CP.01544) was deferred beyond the next regulatory period in 5 scenarios (including the critical scenarios 9 and 13).

When considering both thermal and voltage stability limits into SEQ, we conclude that the increased demand forecasts have advanced the need for augmentation into SEQ. We recommend that the Halys-Blackwall 500 kV double circuit line operating at 275 kV be advanced one year to 2013/14 in critical scenarios to address both long term thermal and voltage stability issues, and that the South Pine SVC project precedes this major augmentation in 2011/12 to mitigate short term voltage stability constraints.

Re-instating the South Pine SVC project in the two critical scenario cases in 2011/12 results in adjustments to Powerlink's proposed capital expenditure as outlined in Table 4.16.

Table 4.16: Recommendations - Impact of 2006 load forecast review on CP.01875 and CP.01544.

$m real 06/07	2007/08	2008/09	2009/10	2010/11	2011/12	TOTAL
Recommended Adjustment in capex – load forecasts CP.01875	-	-	(6.1)	(60.5)	3.2	(63.4)
Recommended Adjustment in capex – load forecasts CP.01544	-	-	-	-	24.1	24.1
Recommended Change in total capex – load forecasts	-	-	(6.1)	(60.5)	27.3	(39.3)

4.4.2 CP.01156/B - Stanwell-Broadsound Second 275kV Circuit

The scope of this project includes stringing the second circuit on existing 275 kV double circuit towers between Stanwell and Broadsound, installation of two new circuit breakers at Stanwell, and use of an existing spare bay at Broadsound to allow the new lines to be switched, monitored and protected from faults.

This project did not incur any expenditure in the 2007-12 regulatory period as part of Powerlink's original revenue application, and is effectively a new project that has been advanced sufficiently to impact on expenditure the 2007-12 expenditure profile. The capital cost estimate of this project is $23.5 million (real, 06/07)

This project has the fifth largest positive impact on the increase in capex sought by Powerlink as a result of the increased 2006 demand forecasts. The increased probability weighted capex associated with this project is around $6.2 million (based on median timing) out of the total $123 million, or 5%. The modified timing and probability of this project that support this increase is presented in Table 4.17.

Table 4.17: Changes in timing and probability of CP.01156/B as a result of updated demand forecasts

Scenario	2005 forecasts		2006 Forecasts		Scenario	2005 forecasts		2006 Forecasts	
	Timing	Probability	Timing	Probability		Timing	Probability	Timing	Probability
1					21				
2					22				
3					23				
4					24				
5					25			31/08/12	6.36%
6					26				
7					27				
8					28				
9			31/08/12	20.38%	29			31/08/12	3.18%
10					30				
11					31				
12					32				
13			31/08/12	11.03%	33				
14					34				
15					35				
16					36				
17					37				
18					38				
19					39				
20					40				
Summated probabilities:									40.94%
Median Timing:								31/08/12	

Note 1, grey shaded cells indicate a scenario in which the timing of the project has been advanced.

To support the advancement of timing associated with this project, Powerlink submitted detailed load flow and constraint analysis data for one of the four scenarios (Scenario 25) but indicated that the results for Scenarios 9, 13 and 29 were very similar.

Powerlink advised that the timing for stringing the second circuit is determined by flows exceeding the winter rating (600 MVA) of the critical Bouldercombe-Broadsound transmission line during a contingency, when the demand in shoulder periods allows for the outage of the first circuit for extended periods. The actual transmission constraint driving the need for the second circuit is forecast to occur in 2014 based on the updated forecast. However, because of the necessity to de-energise the first circuit on the double circuit towers while the second is being strung, the timing to re-string is well in advance of the constraint based need for the augmentation.

The detailed load flow data submitted by Powerlink is presented in Table 4.18.

Table 4.18: Critical winter based line flows for Stanwell-Broadsound project (Scenario 25)

		2008	2009	2010	2011	2012	2013	2014	2015
2005 forecasts	Scen25.1	405	429	438	473	499	529	561	596
	Scen25.2	417	441	453	485	511	541	573	610
	Scen25.3	493	515	528	557	582	612	644	676
	Scen25.4	430	454	466	498	519	554	586	613
	Scen25.5	475	498	511	543	568	601	633	658
	Scen25.6	485	506	518	549	574	597	628	669
2006 forecasts	Scen25.1	458	485	514	544	568	597	618	649
	Scen25.2	470	497	526	556	580	609	630	661
	Scen25.3	546	568	600	627	651	680	710	742
	Scen25.4	483	510	540	568	593	613	653	686
	Scen25.5	528	553	585	614	639	670	687	736
	Scen25.6	536	559	583	619	633	671	701	716

Note 1: Grey shaded cells indicate a forecast line flow which equals or exceeds the rating of the plant. This information has generally been used to determine the timing of augmentation.

Powerlink provided winter based area demand forecasts leading to the power flows in Table 4.18, as follows:

	2007	2008	2009	2010	2011	2012	2013	2014
APR 2005 Forecast								
sub-scenarios 1.2, 4 & 5	1373	1413	1455	1498	1541	1585	1631	1677
sub-scenarios 3 & 6	1326	1364	1404	1445	1487	1529	1572	1617
APR 2006 Forecast								
sub-scenarios 1.2, 4 & 5	1457	1503	1568	1605	1647	1688	1730	1774
sub-scenarios 3 & 6	1408	1452	1514	1549	1590	1629	1669	1711

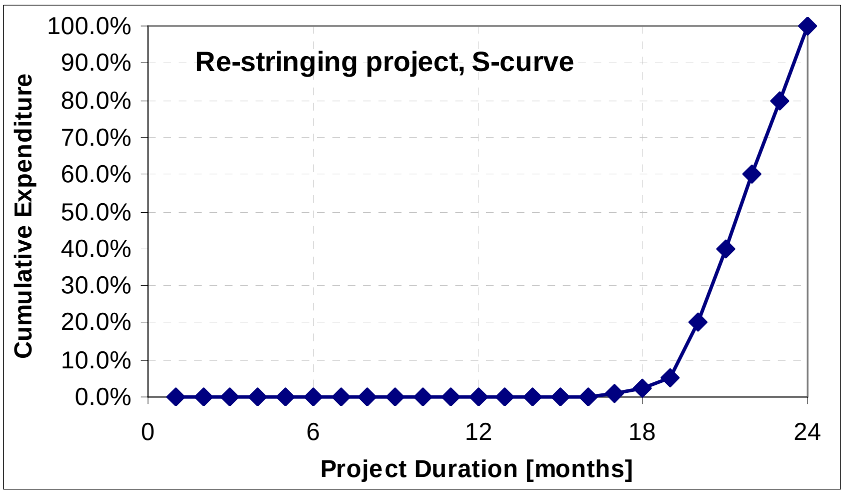
The increase in the area winter load in 2011 is 106 MW for one case, and 103 MW in the other. This increase in demand forecast supports the increase in critical line flows in Table 4.18.

Powerlink concluded, based on an assessment of the cumulative risk across the six sub-scenarios from the 2006 forecast power flows in Table 4.18, that the stringing must take place no later than winter 2012. This is an advancement of 2 years from the same analysis under the 2005 forecast.

While we note that Powerlink has used some discretion and accepted some risk of load shedding in the preceding years of each assessment under some of the sub-scenarios for both sets of forecasts, and that in theory the project could have been advanced even earlier because of this, we conclude that the advancement of this project by two years given the updated forecasts is a reasonable and efficient outcome.

In order to determine the impact on the required capex during the regulatory period, Powerlink has introduced a new and unique S-curve for this type of project, characterised by all expenditure occurring during the last six months of the notional twenty four month project duration. The new S-curve is presented in Figure 4-3.

Figure 4-3: New S-curve for transmission line re-stringing projects.



Assuming the median commissioning date for this project, and as an example of the impact of the demand forecasts on the regulatory period capital expenditure, this S-curve results in the expenditure profile as provided in Table 4.19. Specifically, it indicates that for the 2005 forecast there was no associated expenditure, yet for the 2006 forecasts there is now expenditure in the 2011-12 regulatory year.

Table 4.19: Changes in expenditure profile of CP.01156/B as a result of updated demand forecasts ($,000)

Forecasts	Median C'issioning date	Prob-ability	2007-08	2008-09	2009-10	2010-11	2011-12	Total Reg. Period	Probability Weighted Total Reg. Period
2006	31/08/2012	40.94%	-	-	-	-	15,179	15,179	6,214
2005	-	-	-	-	-	-	-	-	-

We consider this increase in capex within the regulatory period to be a reasonable and efficient outcome given Powerlink's updated winter demand forecasts.

4.4.3 CP.00369/A - Establish Halys 275 kV Substation and Calvale-Halys Circuit

The scope of this project includes the construction of approximately 316 km of overhead 275 kV double circuit transmission line between Calvale and Halys[33] with only one circuit strung, and establishment of a new greenfield substation at Halys comprised of 5 breaker-and-a-half bays. The switchyard will contain 14 new 275 kV circuit breakers to allow the new line, the Tarong to Calvale and the Tarong to Braemar lines to be switched, monitored and protected from faults. Halys is in close proximity to the existing Tarong substation.

As part of Powerlink's initial application, this project was identified in 21 of the 40 scenarios, with a cumulative probability of 25%, and an estimated capital cost within the regulatory review period of $217.53 million (real, 06/07)[34]. The timing of the project was identified as 30/09/2009.

33 This is effectively from the Central West zone into the South West zone.

34 Assuming the projects median commissioning date.

This project is the second most critical project impacted by the increased 2006 demand forecasts. The increased probability weighted capex associated with the project is around $19.9 million[35] out of the $123 million, or 16%. The modified timing and probability of this project that supports this increase is presented in Table 4.20.

Table 4.20: Changes in timing and probability of CP.00369/A as a result of updated demand forecasts

Scenario	2005 forecasts[1]		2006 Forecasts		Scenario	2005 forecasts		2006 Forecasts	
	Timing	Probability	Timing	Probability[2]		Timing	Probability	Timing	Probability
1					21				
2					22			31/10/08	0.93%
3					23			31/10/08	0.00%
4					24			31/10/08	0.00%
5					25				
6					26				
7					27				
8					28				
9					29				
10	31/10/10	1.50%	31/10/08	2.80%	30			31/10/08	0.56%
11	31/10/11	10.07%			31			31/10/08	0.00%
12					32			31/10/08	0.00%
13					33			31/10/08	4.04%
14			31/10/08	1.68%	34			31/10/09	0.61%
15			31/10/08	0.00%	35				
16			31/10/08	0.00%	36			31/10/09	0.00%
17					37				
18			31/10/08	1.50%	38			31/10/09	0.40%
19	31/10/11	4.89%			39				
20			31/10/08	0.00%	40				
Summated probabilities:							16.45%		12.53%
Median Timing:						31/10/11		31/10/08	

Note 1, These probability and timing figures are aligned with Powerlink's original revenue application (as adjusted by the CQ-SQ review, which has resulted in the project occurring in only 3 scenarios as opposed to 21 scenarios) where the PNG theme set was assigned a probability of 50%. Therefore they do not align with the probabilities presented in Table 4.11, which are presented after the reduction of the PNG theme set probability to 0%.

Note 2, 2006 individual scenario probabilities have been changed due to the removal of the PNG gas theme set.

Note 3, grey shaded cells indicate a scenario in which the timing of the project has been advanced.

This project is part of a package of works associated with increasing the CQ-SQ limit, which is designed to ensure the shortfall of load in Southern Queensland is met under N-G-1 credible contingency conditions, allowing for maximum power flows into Queensland from NSW via QNI while giving due consideration to the impact of power

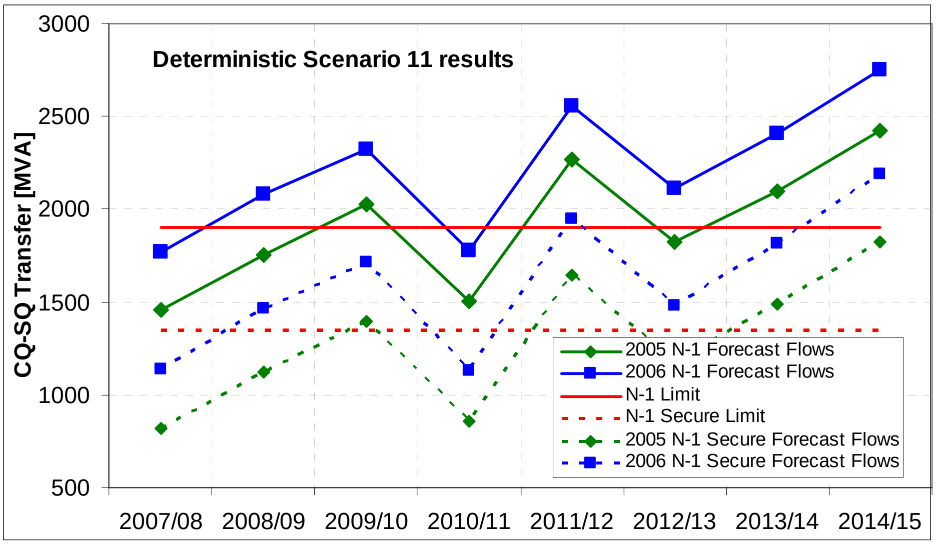
35 Ibid.

flows via DirectLink from/to NSW. The transfer capability is discussed in detail and the CQ-SQ limit equations are published as part of in Powerlink's annual APR.

The CQ-SQ limit is defined by voltage and/or transient stability limits predominantly after loss of one of the long Calvale-Tarong lines and it is measured as the aggregate transfer across the Wurdong-Gin Gin, the two Gladstone-Gin Gin, and the two Calvale-Tarong 275 kV lines. The N-1 limit is nominally 1,900 MW. The 'N-1 secure limit' is nominally 1,350 MW, which represents the transfer capability that can be maintained immediately after the initial event has occurred (i.e. NEMMCO as the system operator has half an hour to secure the system in expectation of a subsequent outage through re-dispatch of generation or run back of DirectLink as necessary). The relevance of presenting the N-1 secure limit is that any augmentation option considered must be capable of improving both the N-1 and the N-1 secure limits.

To support the changes in timing associated with this project, Powerlink submitted detailed load flow and constraint analysis data for two scenarios:

- Scenario 11, where the project was originally required in 2011/12 but has been removed from the network development scenarios after consideration of the updated demand forecasts.



To capture the impacts of the updated demand forecasts, Powerlink has undertaken an identical process to determine and optimise the augmentation projects associated with upgrading the CQ-SQ limit as it undertook in its initial review. Specifically, Powerlink identified a program of solutions for each scenario, which delivered the most economical augmentations for that scenario – there was no single program that optimised the expenditure across all scenarios.

Based on detailed NPV analysis, the preferred option for this scenario for the 2005 forecasts included development of the Palmwoods SVC and Auburn River stage 1 in 2009/10 followed by CP.00396/A (the third Calvale-Tarong line via Halys) in 2011/12.

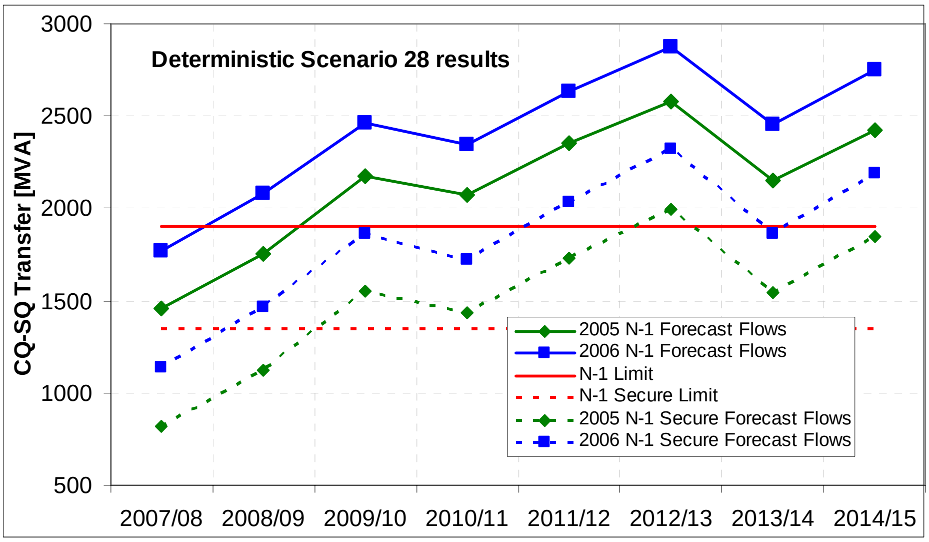
Based on detailed NPV analysis, the preferred option for this scenario for the 2006 forecasts includes CP.00369/B (the third and fourth Calvale-Tarong lines via Halys) in 2008/09, followed by the Palmwoods SVC in 2009/10.

Effectively the single circuit option (CP.00369/A) has been replaced by the double circuit option (CP.00369/B) under the higher forecast demand.

A key observation is that both the N-1 forecast flow and the N-1 secure forecast flow have increased materially as a result of the updated demand forecasts, and that the first year the N-1 forecast flow or the N-1 secure forecast flow exceeds the limits is in 2008/09 as opposed to 2009/10. The results support Powerlink's decision to develop the larger, more effective projects earlier. However, it is not clear what advantage is to be gained from installing the Palmwoods SVC in 2009/10, given the larger transmission development will precede it. Powerlink has advised that the timing of the Palmwoods SVC was not associated with the CQ-SQ review as it was associated with local voltage stability issues in the North Coast/Wide Bay area. Given the high level approach adopted by Powerlink to capture the impacts of increased demand forecasts on voltage stability limits, we highlight that the Palmwoods SVC may be deferred with the onset of other developments – however, there may be some other reactive power support related projects that may have been advanced. Given the time consuming analysis required and the secondary nature of some of the voltage stability related expenditure, we do not recommend any optimisation of the reactive compensation programme of works.

While Powerlink has selected the option which has the lowest NPV in all cases for each scenario, we have observed from the NPV analysis presented that the difference between some options considered was very small and that a more detailed analysis may indicate alternative outcomes. This sensitivity to the assumptions forming the basis of Powerlink's economic assessment may have a material impact on the need for capex over the next regulatory period. The analysis also indicated that Powerlink did not consider the same options when comparing the impact of the 2006 forecasts compared with the 2005 forecasts, and that Powerlink reverted to its experience to consider other options. It would have been beneficial and more transparent if Powerlink had included the original options in the analysis to explicitly indicate why they no longer addressed the constraints.

- Scenario 28, where the project was not and will not form part of the network development scenarios after consideration of the updated demand forecasts.



Based on detailed NPV analysis, the preferred option for this scenario based on the 2005 forecasts included development of the Palmwoods SVC and CP.00369/B (the third and fourth Calvale-Tarong lines via Halys) in 2009/10, followed by Auburn River (three circuits) in 2012/13 and Auburn River (four circuits) and Braemar-Halys in 2015/16 (for which there was no expenditure within the 2007-2012 regulatory period).

Based on detailed NPV analysis, the preferred option for this scenario based on the 2006 forecasts includes CP.00369/B (the third and fourth Calvale-Tarong line via Halys) in 2008/09, followed by the Palmwoods SVC in 2009/10, and Auburn River (four circuits) in 2012/13.

The key observation is that the both the N-1 forecast flow and the N-1 secure forecast flow have increased materially as a direct result of the updated demand forecasts. The results support Powerlink's decision to advance the two circuit project (CP.00369/B) by one year and to not include the single circuit project (CP.00369/A) in the next regulatory period. Further, the need for Auburn switching in 2012/13 is apparent.

An example of the impact of the demand forecasts is provided in Table 4.21, assuming the median commissioning date.

Table 4.21: Changes in expenditure profile of CP.00369/A as a result of updated demand forecasts ($, 000s)

Forecasts	Median Commissioning date	Probability	2007-08	2008-09	2009-10	2010-11	2011-12	Total Reg. Period	Probability Weighted Total Reg. Period
2006	31/10/2008	12.53%	202,575	9,722	-	-	-	212,296	26,605
2005	31/10/2011	2.80%	-	-	20,843	208,154	9,994	238,991	6,702

When considering the efficiency of Powerlink's increased expenditure for this project, we have drawn from the observations from the detailed scenarios analysed. We conclude that the process and outcomes used by Powerlink are reasonable and consistent with its original revenue application.

Review based on 'SQ High 10% PoE' forecast increases

Specifically regarding the CQ-SQ analysis, Powerlink has identified that the treatment of the 'SQ High 10% PoE' demand increases between the 2005 and 2006 periods has not been incorporated into its planning processes accurately. Refer to the characteristics of Figure 4-1. It advised that a fixed industrial load had been treated as a variable component in its analysis and that the actual increase in the area based load is consistent with the update presented in Table 4.22.

Table 4.22: Updated changes to the 2006 forecasts in the SQ based coincident peak demand - 10%PoE conditions (MW)

		2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
SQ	Previous High	218	220	152	247	239	235	228	230
	Updated High	218	220	152	163	156	153	148	151

Powerlink subsequently updated its transmission development plans accounting for this correction and arrived at the following updated project probabilities. We have not had the opportunity to review the probability update process, and accept Powerlink's advice on this matter as outlined in the following table:

Table 1: Impact of 2006 demand forecast on projects for augmentation across the CQ – SQ grid section[1] following the review of the high economic growth SQ forecast.

Project	2005 forecast	2006 forecast	2006 forecast H50 review
Establish Halys 275kV Substation and Calvale to Halys 2nd 275kV Double Circuit 1st Stage (single circuit strung)	2.8%	12.5%	8.5%
Calvale to Halys 2nd 275kV Double Circuit single circuit strung (Halys already established)	0.6%	-%	-%
Establish Halys 275kV Substation and Calvale to Halys 2nd 275kV Double Circuit 1st Stage (both circuit strung)	-%	0.7%	0.7%
Gin Gin 250MVAr SVC	2.1%	16.4%	20.5%
Auburn River Switching Station (2 switched circuits)	5.2%	22.8%	26.8%
Auburn River Switching Station (3 switched circuits)	0.7%	-%	-%
Auburn River Switching Station (4 switched circuits)	-%	2.8%	2.8%
Easement Acquisition for Calvale to Halys 2nd 275kV Double Circuit Line (TE)	3.6%	12.7%	9.2%
Easement Acquisition for Calvale to Halys 2nd 275kV Double Circuit Line (Compensation)	3.6%	12.7%	9.2%

Powerlink has advised that the overall impact of this correction is to reduce the capex forecast over the next revenue period by $5.56 million (real, 06/07).

Ability to construct advanced programme

Referring to the updated project timings for the three key projects related to the 275kV transmission between Calvale-Halys and Braemar-Halys (CP.00369, CP.00369/A and CP.00369/B, as presented in Appendix K), it is observed that based on the 2005 forecasts[36] either or both of the Calvale-Halys lines were needed in only five scenarios with the earliest timing being 2009/10. With the revised forecast either or both lines are required in 22 scenarios and in most cases in 20 months time i.e. October 2008.

Powerlink has provided confidential information regarding its ability to deal with the advanced construction program between Calvale-Halys, and believes the flexible construction arrangements in place for transmission line and substation works under period agreements it holds will allow it to achieve the required outcomes.

Given Powerlink's existing project programme, and no information regarding whether the easements, planning permits or environmental impact assessments for this advanced project have been activated or not, we have some concerns about Powerlink's ability to incorporate these three projects (particularly CP.00369/A - the double circuit Calvale-Halys line) into its current activities without deferring other discretionary projects. This raises the issue that Powerlink may increase its forecast capex requirement but be unable to actually spend the additional allocation. This would be an inefficient outcome. However, considering the risk is associated with the advancement of a relatively small sum of $14.5 million in over $2.4 billion, we consider that it is reasonable to allow this level of increased capex into the next regulatory period for this project. We highlight that Powerlink's preliminary NPV assessment indicates the identified sequence of works provides the most economical outcome.

Nevertheless, Powerlink noted in its original revenue application that delivery of its proposed construction program would be a challenge and it has implemented a number of initiatives to ensure that the increased work volume can be delivered. The program proposed in its supplementary revenue application will further increase this pressure. We recommend that, before approving this component of Powerlink's supplementary revenue proposal, the AER seeks further assurances form Powerlink that resources will be available to deliver the accelerated program. This will reassure the AER that the risk of an inability to complete the Calvale-Halys development in the advanced time frame is actually quite small.

36 As adjusted by the CQ-SQ review.

4.5 CONCLUSIONS ON IMPACT OF REVISED DEMAND FORECASTS

While we note that we have not been asked to or undertaken a review of the accuracy, validity or reasonableness of Powerlink's revised demand forecasts, we have reviewed the process and outcomes of Powerlink's treatment on the basis that the updated demand forecasts can be relied on.

Given the strong relationship between the demand forecast and required capital expenditure, it is clear that there is some need to increase Powerlink's forecast of capex in the coming regulatory period given the updated demand forecasts resulted in an increase in the critical peak summer demands[37]. In general, we have found there is a need to advance the timing of transmission development plans given the size of the increases in peak summer demand forecasts.

Powerlink has:

- Adopted a rigorous and systematic, but time constrained, review involving identification of 40 new transmission development plans for 5 critical geographic based load zones in Queensland. This has been based on a fundamentally consistent approach with that used in the development of its original application but has been restricted to the consideration of thermal limitations only, except for a subsequent review of the voltage stability limit into SEQ.

- Identified a reduction of $5.6 million due to the inaccurate application of the revised demand forecast in the high economic growth, 10% PoE scenario.

We recommend:

- Powerlink's proposed increase in capex due to increased demand forecasts be moderated, as a prudent and economically efficient alternative to the most critical project suggests that the development of the Halys-Blackwall 500 kV lines operating at 275 kV should be advance by one year in critical scenarios not three years, in conjunction with the advancement of the Southpine SVC project into the next regulatory period.

- Powerlink provide further assurances to the AER regarding its ability to deliver the revised programme of works.

Our overall recommendations regarding the impact of the increased Queensland demand forecast are presented in Table 4.23.

Table 4.23: Recommendations - Impact of 2006 load forecast review on total forecast capital expenditure

$m real 06/07	2007/08	2008/09	2009/10	2010/11	2011/12	TOTAL
Proposed Change in total capex – load forecasts	55.12	54.42	(57.27)	50.33	26.4	129.0
Recommended Adjustment in capex – load forecasts CQ-SQ review	-	-	-	(2.78)	(2.78)	(5.6)
Recommended Adjustment in capex – load forecasts SWQ-SEQ review	-	-	(6.1)	(60.5)	27.3	(39.3)
Total Adjustment	-	-	(6.1)	(63.28)	24.52	(44.9)
Recommended Change in total capex – load forecasts	55.12	54.42	(63.37)	(12.95)	50.92	84.1

37 As an example of the updates, the medium economic growth 10% PoE forecast for 2007/08 increased by 255 MW (or 2.9%) from 8,936 MW to 9,191 MW between the publication of the 2005 and 2006 APR's.

APPENDIX A

Terms of reference

Appendix A: Terms of reference

Annex B

Consultancy Terms of Reference - Powerlink Revenue Reset

Review of Powerlink's supplementary submission

Background

The Australian Energy Regulator (AER), in accordance with its responsibilities under the National Electricity Rules (rules), is conducting an inquiry into the appropriate revenue cap to be applied to the non-contestable elements of the transmission services provided by Powerlink Queensland (Powerlink) from 1 July 2007 to 30 June 2012.

On 3 April 2006, Powerlink submitted a revenue proposal for the period 1 July 2007 to 30 June 2012. The AER engaged PB Associates (PB) to review Powerlink's proposed capital expenditure, historic capital expenditure, operational expenditure and service standards proposals. The AER's draft decision and PB's final consultancy report was released on 8 December 2006.

On 15 December 2006, Powerlink submitted a supplementary revenue proposal for the period 1 July 2007 to 30 June 2012. Powerlink stated that new and relevant information had emerged since it submitted its initial proposal. It noted that the new information results in revisions to Powerlink's main ex ante capital allowance and consequential adjustments to operating expenditure allowances and that this information must be taken into account in the AER's final decision. The supplementary revenue proposal is at Attachment A.

Powerlink's supplementary revenue proposal included information on:

- a review of projects in the Central Queensland –South Queensland grid section
- revised capital cost estimates for assets under construction and capital projects in the next regulatory period
- the advancement in timing of projects based on the 2006 demand forecasts
- the revised probability of generation from PNG gas pipeline
- a requirement by NEMMCO to install high speed monitoring equipment.

The AER seeks to engage an appropriately qualified technical consultant to undertake a review of certain aspects of Powerlink's supplementary submission including whether:

- the additional forecast capex sought by Powerlink based on revised cost estimates for assets under construction and projects that commence in the next regulatory period is reasonable and efficient.
- the additional forecast capex sought by Powerlink based on its 2006 demand forecasts is reasonable and efficient.

- the additional forecast capex sought by Powerlink based on its revised probability of PNG gas generation is reasonable and efficient.

Terms of reference

1. Revised capital cost estimates

Assets under construction

Powerlink's revenue proposal included a number of capital projects which incur expenditure across the current and next regulatory period. Powerlink stated that the capital cost estimates for these projects have been updated to reflect recent increases in input costs. Powerlink indicated that since estimates were prepared for approval of those projects in the second half of 2005, the cost of tower steel has increased by at least 15 per cent, copper by 100 per cent and aluminium for conductors by 40 per cent. Powerlink stated that the revised cost estimates for assets under construction results in a $156 million increase in forecast capex from its initial proposal.

The consultant should comment on whether the revised cost estimate is efficient. The review should:

- Identify the assets under construction where Powerlink revised its cost estimates.
- Describe and evaluate the evidence/material that Powerlink have relied upon when determining the increase in the proposed forecast capex allowance including contractor quotes, internal estimates and material prices.
- Assess whether the process Powerlink has undertaken to review its cost estimates is robust including whether the revised estimated cost is likely to reflect the actual efficient cost of the project.
- Where projects have been subject to cost revisions, comment on whether the project has been managed in accordance with Powerlink's corporate governance framework.

The consultant's review on the revised cost estimates for assets under construction should be informed by a detailed review of three projects. The detailed review should:

- Identify the cost difference between the estimate in the initial Powerlink application and the estimate in the supplementary revenue proposal.
- Analyse the impact of material price increases on the revised cost estimate.
- Discuss the process Powerlink has undertaken to revise the estimated cost of the project including competitive tendering processes.
- Assess whether the revised cost estimate for the project is likely to be the efficient cost of the project in the current market conditions.

Key deliverable

- The consultant is to assess whether the increase in Powerlink's proposed forecast capex allowance based on the revised cost estimates for assets under construction is efficient. If the consultant does not agree with Powerlink's proposed increase in forecast capex, it must determine a higher or lower alternative estimate based on its findings.

Cost increases for projects that commence expenditure in the next regulatory period

Powerlink revised its unit costs for projects that commence expenditure in the next regulatory period. The revised unit costs were based on updated cost estimates for assets under construction including transmission lines and substation projects. Powerlink estimated that the change in unit costs results in an increase of $126 million from its initial proposal.

The consultant's review should provide an assessment of whether the revised unit costs will result in efficient investment. In particular, the consultant should:

- Identify the unit costs (BPOs) which have been revised by Powerlink including the magnitude of change.
- For each BPO that has been revised by Powerlink (eg 100km overhead transmission line) provide a breakdown of the proportion of costs for aluminium, zinc, tower steel, copper and labour.
- Assess whether the revised unit costs reflect current market conditions giving consideration to the consultant's findings on assets under construction.
- Assess whether the revised unit costs are efficient for projects that commence in the next regulatory period or whether the unit costs are likely to be higher or lower than the revised estimate.

Key deliverable

- The consultant is to assess whether the increase in Powerlink's proposed forecast capex allowance based on the revised cost estimates for projects in the next regulatory period is efficient. If the consultant does not agree with Powerlink's proposed increase in forecast capex, it must determine a higher or lower alternative estimate based on its findings.

2. Impact of demand forecasts on augmentations

Powerlink's initial proposal relied on 2005 demand forecasts. Powerlink stated that the 2006 demand forecasts, published after its initial application, should be taken into account in the final decision. It noted that the 2006 demand forecasts advance the timing of augmentations in some regions of the network. Powerlink stated that this results in an increase in forecast capex of $129 million from Powerlink's initial proposal.

The consultant's review should:

- Identify the difference in peak demand forecasts between the 2005 and 2006 Annual Planning Report across Queensland and the ten zones of Powerlink's transmission network.
- Identify the projects that Powerlink proposed to be advanced in timing as a result of higher peak demand forecasts.
- Assess whether there is a need to advance timing for the projects identified by Powerlink.
- Assess whether there are any other projects that need to be advanced or deferred in timing as a consequence of the 2006 demand forecasts.

The consultant's assessment should be informed by a detailed review of 3 projects that Powerlink proposed to advance in timing.

Key deliverable

- The consultant is to assess whether the increase in Powerlink's proposed forecast capex allowance based on the 2006 demand forecasts is efficient. If the consultant does not agree with Powerlink's proposed increase in forecast capex, it must determine a higher or lower alternative estimate based on its findings.

3. PNG gas generation

Powerlink stated that the PNG gas project is not expected to result in any associated generation developments in the Townsville area in the next regulatory period. It noted that the capex forecast has been re-evaluated by assigning a zero per cent probability to the development of generation associated with the PNG gas pipeline resulting in an increase of $57 million from the initial proposal.

The consultant's review should:

- Comment on whether a zero per cent probability for the PNG gas generation scenario is reasonable.
- Identify new projects or projects that have been advanced in timing as a consequence of the revised probability of PNG gas generation.
- Assess whether the new projects or the projects that have been advanced reflect efficient investment outcomes. When making this assessment the consultant should consider whether there are any possible alternative generation developments including coal seam methane that would reduce the need or defer augmentation in north or central Queensland.

The consultant's assessment should be informed by a detailed review of 1 project that Powerlink proposed to advance in timing as a result of the revised probability for PNG.

Key deliverable

- The consultant is to assess whether the increase in Powerlink's proposed forecast capex allowance based on the revised probability of generation from the PNG gas project is appropriate and efficient. If the consultant does not agree with Powerlink's proposed increase in forecast capex, it must determine a higher or lower alternative estimate based on its findings.

Timing and outcomes

The AER expects to release its final decision in April 2007. Given this timeline the draft consultancy report must be provided to AER no later than 15 February 2007 and the final report no later than 28 February 2007.

The final consultancy report will be released publicly at the same time the AER's final decision is published.

Consultation process

The consultant will be required to liaise extensively with Powerlink during the course of the review. These consultations will include:

- written requests to Powerlink for additional information and documentation
- meetings with Powerlink staff at their Brisbane offices

The consultant will also be required to liaise extensively with AER staff and provide regular updates on:

- progress towards achieving the deliverables
- any impediments that have arisen to achieving those deliverables
- the quality and timeliness of responses made by Powerlink to written requests for information
- significant issues that have been identified.

APPENDIX B

Future projects

Project No.	Description	2007-08	2008-09	2009-10	2010-11	2011-12	Total Reg
		- - - - - - - - - - - - - - N o m i n a l - - - - - - - - - - - - - -					
CP.00369	Establish Halys 275kV Substation and Braemar to Halys 500kV DCST operating at 275kV	0.071	0.738	0.453	3.388	0.892	5.542
CP.00369/A	Establish Halys 275kV Substation and Calvale to Halys 2nd 275kV DCST 1st stage (single circuit strung)	-	0.024	0.493	2.550	0.125	3.192
CP.00369/B	Establish Halys 275kV Substation and Calvale to Halys 2nd 275kV DCST 1st stage (both circuit strung)	0.053	0.548	0.027	-	-	0.628
CP.00376	Palmwoods 3rd 275/132kV 300MVA Transformer (was CP.01688)	-	0.136	0.587	0.235	0.065	1.023
CP.00390	Rocklea 275kV bus & 3rd 300MVA 275/110kV transformer	0.039	0.147	0.001	-	0.432	0.619
CP.00659/A	El Arish 132/22kV Substation Establishment	1.011	0.379	0.024	-	-	1.414
CP.00775/B	Braemar to Halys 500kV DCST line operating at 275kV (Halys already established)	-	-	0.012	0.125	0.006	0.143
CP.00880	Cardwell - Tully Replacement	-	-	-	0.589	1.988	2.577
CP.00881	Yabulu - Ingham Line Replacement	-	0.329	2.517	1.680	-	4.526
CP.00882	Ingham - Cardwell Line Replacement	-	-	0.170	1.679	0.360	2.209
CP.01016	Nebo Secondary Systems Replacement	-	-	0.135	0.493	-	0.628
CP.01017	Tarong Partial Secondary Systems Replacement (was CP.01571)	-	-	0.321	1.412	0.113	1.846
CP.01018/A	Swanbank A Rebuild	0.075	0.299	0.849	-	-	1.223
CP.01021	Lilyvale Secondary Systems Replacement	-	-	0.015	0.349	0.227	0.591
CP.01024	Belmont Secondary Systems 110kV Replacement	-	0.016	0.261	0.453	-	0.730
CP.01064	Gin Gin Secondary Systems Replacement	0.104	0.458	0.036	-	-	0.598
CP.01119/A	Oakey 110/33kV Substation Establishment	0.015	-	-	-	-	0.015
CP.01127	Loganlea 110kV Secondary Systems Replacement	-	-	0.047	0.292	0.053	0.392
CP.01130	QAL 132/11KV Transformer Replacements	1.390	0.058	-	-	-	1.448
CP.01133	Belmont No4 Transformer Replacement	-	-	-	0.540	0.261	0.801
CP.01135	Redbank Plains Secondary Systems Replacement (was CP.01562)	-	-	-	0.010	0.094	0.104
CP.01147	Belmont No5 Transformer Replacement	-	0.193	0.643	0.005	-	0.841
CP.01148	Wurdong Secondary Systems Replacement (was CP.01569)	-	-	-	0.064	0.400	0.464
CP.01162	Callemondah Secondary Systems Replacement (was CP.01570)	-	-	-	-	0.038	0.038
CP.01163	Swanbank B 275kV Rebuild (was CP.01646)	-	-	0.297	1.184	3.374	4.855
CP.01165	West Darra Switchyard Replacement	0.605	0.715	-	-	-	1.320
CP.01166	Palmwoods Secondary Systems Replacement	-	-	0.005	0.133	0.424	0.562
CP.01169	Innisfail - Edmonton Line Replacement	-	0.399	3.020	0.036	-	3.455
CP.01178	Kamerunga Secondary Systems Replacement	-	-	0.051	0.186	-	0.237
CP.01189/B	Southpine to Sandgate 275kV DCST @ 110kV	0.195	0.709	0.004	-	0.048	0.956
CP.01195/A	Larapinta 275kV Substation Establishment	0.255	0.622	2.809	1.361	0.152	5.199
CP.01249	South Coast Transmission Reinforcement Stage 1	0.009	0.192	0.962	0.047	-	1.210
CP.01258	Rocklea/Tennyson 110kV series reactor	0.007	-	-	-	-	0.007
CP.01259	Woree 132kV Feeders bays for Cairns North	0.086	0.012	0.032	-	-	0.130
CP.01264/A	Woolooga to North Coast 275kV Double Circuit and 275/132kV Transformer	0.032	0.330	0.344	3.372	0.166	4.244
CP.01268	Woree 3rd 132kV 50MVAr Capacitor Bank	-	-	0.002	0.028	0.121	0.151
CP.01269	Woree 4th 132kV 50MVAr Capacitor Bank	-	-	-	0.001	0.009	0.010
CP.01280	Calvale-Larcom 275kV T/L + Larcom + CAR + Algoda	0.145	0.838	0.005	-	-	0.988
CP.01292	Broadsound Secondary Systems Replacement	-	-	-	0.107	0.394	0.501
CP.01293	Ross Secondary Systems Replacement	-	-	0.058	0.370	0.067	0.495
CP.01300	Loganlea 110kV Extensions (Browns Plains)	0.001	-	-	-	-	0.001
CP.01301	Power Quality Monitoring Stages 1&2	-	-	0.373	0.152	0.003	0.528
CP.01316	Rocklea 4th 110kV 50 MVAr Capacitor Bank	0.004	0.040	0.002	-	-	0.046
CP.01317	Ashgrove West 3rd 110kV 50 MVAr Capacitor Bank	0.002	0.041	-	-	-	0.043
CP.01512/A	Strathmore-Ross 275kV DCST - both circuits strung (paralleled operation)	0.052	0.722	1.947	0.094	-	2.815
CP.01514	Kamerunga 3rd 132/22kV Transformer	-	0.008	0.026	-	0.082	0.116
CP.01516	South East Brisbane No. 1 110/11kV Substation Establishment - Stage 1	-	0.102	0.359	0.029	-	0.490
CP.01516/A	South East Brisbane No. 1 110/11kV Substation Establishment - Stage 1 & 2	0.035	-	-	-	-	0.035
CP.01517	South East Brisbane No. 2 110/11kV Substation Establishment - Stage 1	-	0.116	0.519	0.083	-	0.718
CP.01517/A	South East Brisbane No. 2 110/11kV Substation Establishment - Stage 1 & 2	0.013	0.060	0.009	-	-	0.082
CP.01520	Brisbane South No. 1 110/11kV Substation Establishment - Stage 1	-	0.173	0.533	0.008	-	0.714
CP.01520/A	Brisbane South No. 1 110/11kV Substation Establishment - Stage 1 & 2	0.020	0.061	0.001	-	-	0.082
CP.01522/A	South West Brisbane No. 2 110/11kV Substation Establishment	-	-	-	0.015	0.066	0.081
CP.01523	Townsville East 2nd 132/66kV 100MVA Transformer	0.029	0.014	0.296	0.142	-	0.481
CP.01524	South West Brisbane No.1 110/33kV Substation Establishment	-	-	0.021	0.071	0.003	0.095
CP.01528/A	Molendinar 3rd 275/110kV 300MVA transformer	0.199	1.022	0.130	0.384	0.022	1.757
CP.01533/B	275kV Double Circuit Line into South West Brisbane	0.084	0.002	-	0.106	0.880	1.072
CP.01537	Greenbank to Mudgeeraba SCST to DCST	0.213	0.005	-	-	0.288	0.506
CP.01540	Middle Ridge 1st Transformer upgrade to 1500MVA	0.002	-	0.002	0.002	0.001	0.007
CP.01543/A	Mudgeeraba 1st & 2nd 275/110kV Transformer Augmentation	-	-	0.032	0.108	0.001	0.141
CP.01544	Southpine 350MVAr SVC	-	-	0.851	0.744	0.618	2.213
CP.01545	Abermain No 2 Transformer	0.097	0.323	0.002	-	-	0.422
CP.01548	Kareeya Substation Redevelopment	-	0.183	0.823	0.134	-	1.140
CP.01549	Moura Switchyard Replacement	-	-	0.151	0.675	0.109	0.935
CP.01552	Brisbane West Transition Point	-	0.001	0.005	-	-	0.006
CP.01553	Brisbane West 110/11kV Substation Establishment	-	-	-	0.014	0.043	0.057
CP.01554	North West Brisbane No. 1 110/33kV Substation Establishment	-	-	0.015	0.053	0.157	0.225
CP.01563	Bouldercombe Secondary Systems Replacement	-	-	-	0.025	0.543	0.568
CP.01566	Chalumbin Secondary Systems Replacement	-	-	-	0.050	0.552	0.602
CP.01572	Cardwell Secondary Systems Replacement	-	0.003	0.034	0.012	-	0.049
CP.01574	Alligator Creek Secondary Systems Replacement	0.138	0.011	-	-	-	0.149
CP.01581	North Goonyella Secondary Systems Replacement	-	-	0.004	0.007	-	0.011
CP.01582	Stanwell Secondary Systems Replacement	-	-	-	0.152	0.669	0.821
CP.01591	South East Brisbane No. 2 110/11kV Transformer Bay - Stage 2	-	-	-	0.071	0.266	0.337
CP.01592	Brisbane South 110/11kV Transformer - Stage 2	-	-	-	0.051	0.262	0.313
CP.01594	Abermain 2nd 275/110kV 300MVA Transformer	-	-	0.017	0.066	-	0.083
CP.01595	South West Brisbane 275/110kV Transformer Augmentation	-	-	-	-	0.022	0.022
CP.01599	Southpine 110kV Feeder Bays for Griffin	0.073	-	0.003	0.009	0.027	0.112
CP.01600	Palmwoods 132kV Feeder Bays for Marcoola	0.099	-	-	0.014	0.036	0.149
CP.01602	Abermain 110kV Feeder Bays for Wulkuraka	0.035	0.081	0.001	-	-	0.117
CP.01606	Clare 132kV Feeder Bays for Millchester No2	0.001	0.003	0.016	0.029	0.085	0.134
CP.01607	Pandoin 132kV Feeder Bay Yeppoon	0.002	0.008	0.026	0.090	0.003	0.129
CP.01608	South East Brisbane No. 1 110/11kV Transformer Bay - Stage 2	-	-	-	-	0.005	0.005
CP.01612	Black River 132/66kV Substation Establishment	-	-	0.014	0.049	0.002	0.065
CP.01615	Auburn River Switching Station (2 switched circuits)	0.083	0.371	0.061	-	-	0.515
CP.01615/D	Auburn River Switching Station (3 switched circuits)	-	- 0.015	- 0.068	- 0.011	-	- 0.094
CP.01620	Bouldercombe 275/132kV transformer Reinforcement	-	-	-	0.017	0.067	0.084
CP.01622	Cardwell Substation Line Switching	-	0.031	0.141	0.022	-	0.194
CP.01623	Kamerunga Bus Section circuit breaker	0.012	0.057	0.009	-	-	0.078
CP.01628	Alligator Creek 132kV Feeders bays for Louisa Creek	0.265	0.021	-	-	-	0.286
CP.01629	Middle Ridge 110/33kV 100MVA Transformers	-	0.041	0.020	-	0.433	0.494
CP.01631/A	West Darra Transformer Bay for 1st West Darra 110/11kV Transformer	0.119	0.254	-	-	-	0.373
CP.01632	Garbutt 3rd 132/66kV 80MVA Transformer	-	-	0.010	0.028	-	0.038
CP.01635	Abermain Secondary Systems Replacement	-	-	-	-	0.016	0.016
CP.01659	Callide A 132kV Feeder Bay for Monto Mine	0.016	0.060	0.163	-	-	0.239
CP.01662	Blackwater 132kV Feeder Bay for Emerald	0.030	0.105	0.004	-	-	0.139
CP.01663	Proserpine 132kV Feeder Bays for Canonvale	-	0.009	0.024	0.092	0.249	0.374
CP.01664	Kamerunga 132kV Feeder Bays for Kewarra Beach	-	-	-	0.003	0.013	0.016
CP.01679	Mudgeeraba 110kV Rebuild	-	-	-	0.467	2.097	2.564
CP.01684	Swanbank A 2nd 275/110kV Transformer Connection	0.004	0.010	-	0.038	0.107	0.159
CP.01687	North Coast 275/110kV Transformer	0.024	0.069	0.001	-	-	0.094
CP.01705	Calvale to Wurdong 275kV DCST Line	0.236	1.974	0.171	0.798	0.051	3.230

CP.01706	Gladstone to Larcom Creek Rebuild SCST to DCST Line (both ccts turned in)	0.002	0.018	0.012	0.005	-	0.037
CP.01706/B	Gladstone to Larcom Creek Rebuild SCST to DCST Line (circuits paralleled)	-	-	-	-	0.008	0.008
CP.01707	Larcom Creek to Bouldercombe Rebuild SCST to DCST Line (both ccts turned in)	-	0.003	0.027	0.013	-	0.043
CP.01707/A	Larcom Creek to Bouldercombe Rebuild SCST to DCST Line (one cct turned in)	-	-	-	-	0.029	0.029
CP.01714/A	Substation Access Security (Part A)	-	0.892	2.453	-	-	3.345
CP.01714/B	Substation Access Security (Part B)	-	-	-	0.987	2.713	3.700
CP.01717/A	Transmission Line Structure Security Upgrade (Part A)	0.411	3.476	0.081	-	-	3.968
CP.01717/B	Transmission Line Structure Security Upgrade (Part B)	-	-	0.452	3.830	0.090	4.372
CP.01718	Braemar 3rd 1500MVA 330_275kV Transformer	-	0.001	0.014	0.045	0.006	0.066
CP.01719	Molendinar 3rd 110/33kV 100MVA Transformer	-	0.005	0.024	0.003	0.051	0.083
CP.01720	Innisfail 2nd 132kV 20MVAr Capacitor Bank	-	-	-	0.004	0.007	0.011
CP.01721	South Coast Transmission Reinforcement Stage 2	-	-	0.012	0.100	0.003	0.115
CP.01722/B	Calvale to Halys 2nd 275kV DCST 1st stage (single circuit strung)	-	0.050	0.520	0.026	-	0.596
CP.01747	Runcorn 3rd 110kV Transformer	-	-	-	0.012	0.039	0.051
CP.01748	Ashgrove West 2 x 100MVA 110/33kV Transformers	-	0.008	0.033	0.001	0.089	0.131
CP.01751	Middle Ridge - Murphys Creek @ 110kV for Postmans Ridge	0.095	0.028	-	-	-	0.123
CP.01752	Woolooga Uprate Feeder Bays for Gympie Circuits	0.070	0.165	0.002	-	0.022	0.259
CP.01754	Richlands 2 x 110kV feeder bays	0.009	0.035	0.106	0.034	-	0.184
CP.01756	Runcorn 2 x 110kV feeder bays	0.016	0.034	0.099	0.032	-	0.181
CP.01757	Collinsville Transformer and 33kV cable upgrades	0.002	0.008	0.022	0.021	0.084	0.137
CP.01758	Pioneer Valley Replace 52MVA with 100MVA	0.005	0.015	0.054	0.152	0.001	0.227
CP.01760	Sarina 1st 132/66kV Transformer	0.014	0.053	0.147	0.548	0.004	0.766
CP.01761	Alligator Creek 1st 132/66kV Transformer	-	-	-	0.007	0.028	0.035
CP.01762	2nd Calvale Tx	0.015	0.069	0.048	0.036	0.002	0.170
CP.01763	Tarong 275/132kV Transformers Upgrade	-	-	0.015	0.056	-	0.071
CP.01764	Braemar 275/132kV Substation Establishment	0.166	0.001	-	-	-	0.167
CP.01765	Middle Ridge 110kV bay for Warwick	-	-	-	-	0.001	0.001
CP.01766	Cairns West 132/22kV substation establishment	-	-	-	0.021	0.131	0.152
CP.01767	Gladstone to Wurdong DCST Line	0.002	0.022	0.003	0.017	0.001	0.045
CP.01769	Murrarie 110kV Bay for 2nd Wakerley 110/33kV TX	-	-	0.002	0.007	-	0.009
CP.01771/B	Goodna to Larapinta 275kV DCST	0.193	0.005	-	0.248	2.062	2.508
CP.01772	Upper Kedron - Karana 275kV DCST Uprate Existing	-	-	-	0.001	0.003	0.004
CP.01774	Larapinta 275kV Line Reconfiguration of Blackwall to Belmont DCST	0.036	0.003	-	0.116	0.410	0.565
CP.01780	Gladstone PS Switchyard Rebuild	-	1.251	5.668	0.930	-	7.849
CP.01782	Blackwall to Swanbank Uprate Existing 275kV - Built Section 1014 and 1064	0.003	0.051	0.218	0.014	0.081	0.367
CP.01784	Calvale 275kV Substation Refurbishment	-	-	0.086	0.386	0.062	0.534
CP.01792	Karana Double Tee from Upper Kedron	0.001	0.002	-	-	0.005	0.008
CP.01794/C	South West Qld to South East Qld 500kV DCST	-	-	-	-	0.109	0.109
CP.01798/A	Wurdong to South Pine Earthwire Replacement (Part A)	0.232	1.124	2.008	-	-	3.364
CP.01798/B	Wurdong to South Pine Earthwire Replacement (Part B)	-	-	-	0.836	2.820	3.656
CP.01821	North Goonyella Upgrade	-	0.051	0.203	0.574	-	0.828
CP.01822	Ashgrove West Cables Replacement	-	-	-	-	0.041	0.041
CP.01836	Gin Gin 250MVAr SVC	0.151	0.263	0.006	-	-	0.420
CP.01839	Cedar Creek 275/110kV Substation Establishment	-	-	-	-	0.044	0.044
CP.01843	Palmwoods Quad Boost Transformer	-	0.014	0.007	-	0.156	0.177
CP.01844	Southpine Transformer Augmentation and 110kV Split Bus	0.268	1.030	0.342	0.011	-	1.651
CP.01868	Sandgate to Nudgee 275kV DCST and Nudgee 275/110kV Substation Establishment	-	-	-	0.077	0.270	0.347
CP.01870	West Darra Transformer Bay for 2nd West Darra 110/11kV Transformer	-	0.004	0.011	0.042	0.113	0.170
CP.01875	Halys to Blackwall 500kV operating at 275kV	-	0.006	0.139	0.803	0.239	1.187
CP.01876	Edmonton 2nd 132kV 30MVAr Capacitor Bank	-	-	-	-	0.005	0.005
CP.01879	Millmerran to Bulli Creek 500kV operating at 330kV	-	-	-	-	0.042	0.042
CP.01880	Moreton Central 120MVAr No 1	0.042	-	-	-	-	0.042
CP.01881	Moreton Central 120MVAr No 2	0.062	0.012	-	-	-	0.074
CP.01882	Moreton Central 120MVAr No 3	0.016	0.071	0.055	0.041	0.012	0.195
CP.01883	Moreton Central 120MVAr No 4	0.001	0.012	0.040	0.075	0.028	0.156
CP.01884	Moreton Central 120MVAr No 5	-	0.001	0.013	0.068	0.051	0.133
CP.01885	Moreton Central 120MVAr No 6	-	-	0.002	0.024	0.045	0.071
CP.01886	Moreton South 120MVAr No 1	0.033	-	0.001	0.003	0.014	0.051
CP.01887	Moreton South 120MVAr No 2	0.008	0.034	0.027	0.053	0.018	0.140
CP.01888	Moreton South 120MVAr No 3	0.008	0.003	0.012	0.054	0.045	0.122
CP.01889	Moreton South 120MVAr No 4	0.003	0.007	0.010	0.025	0.027	0.072
CP.01896	Moreton South 120MVAr No 5	0.002	0.009	0.005	0.015	0.010	0.041
CP.01897	Moreton South 120MVAr No 6	-	0.002	0.009	0.006	0.001	0.018
CP.01898	Moreton South 120MVAr No 7	-	-	0.003	0.009	0.003	0.015
CP.01899	Moreton South 120MVAr No 8	-	-	0.003	0.009	0.003	0.015
CP.01900	Moreton South 120MVAr No 9	-	-	0.001	0.003	0.001	0.005
CP.01901	Moreton South 120MVAr No 10	-	-	-	0.001	0.002	0.003
CP.01904	Moreton Central 120MVAr No 7	-	-	0.001	0.008	0.013	0.022
CP.01905	Moreton Central 120MVAr No 8	-	-	-	0.002	0.009	0.011
CP.01908	Moreton South East 120MVAr No 1	0.004	0.010	0.010	0.047	0.028	0.099
CP.01909	Moreton South East 120MVAr No 2	0.001	-	-	0.001	0.004	0.006
CP.01914	Tarong 120MVAr No 1	-	-	0.004	0.028	0.028	0.060
CP.01915	Gladstone Zone 120MVAr No 1	0.017	0.002	0.003	0.022	0.008	0.052
CP.01916	Gladstone Zone 120MVAr No 2	-	-	-	0.001	0.009	0.010
CP.01918	Strathmore iPASS Secondary Systems Replacement	-	-	0.004	0.072	0.176	0.252
CP.01919	Blackwall & Loganlea iPASS Secondary Systems Replacement	-	-	-	0.123	0.772	0.895
CP.01920	Bulli Creek, Millmerran & Braemar iPASS Secondary Systems Replacement	-	-	-	-	0.269	0.269
CP.01924	Spare 330/275 kV transformer (at Braemar)	0.179	0.596	0.004	-	-	0.779
CP.01926	Alligator Creek 132/33 kV Transformer Replacements	1.345	0.056	-	-	-	1.401
CP.01929	Southpine 4th 110kV 50 MVAr Capacitor Bank	-	0.005	0.042	0.001	-	0.048
CP.01930	Belmont 4th 110kV 50 MVAr Capacitor Bank	-	0.005	0.042	0.001	-	0.048
CP.01931	Loganlea 4th 110kV 50 MVAr Capacitor Bank	-	0.005	0.035	0.010	-	0.050
CP.01932	Moreton North 1st 110kV 50 MVAr Capacitor Bank	0.027	0.005	0.009	0.001	-	0.042
CP.01933	Moreton North 2nd 110kV 50 MVAr Capacitor Bank	-	0.004	0.002	0.045	-	0.051
CP.01934	Moreton North 3rd 110kV 50 MVAr Capacitor Bank	-	0.001	0.003	-	0.004	0.008
CP.01935	Moreton North 4th 110kV 50 MVAr Capacitor Bank	-	-	-	-	0.006	0.006
CP.01936	Moreton North 5th 110kV 50 MVAr Capacitor Bank	-	-	-	0.001	0.003	0.004
CP.01942	Collinsville - Proserpine 132 kV TL Life Extension	-	-	-	0.241	2.081	2.322
CP.01957	Calvale to Larcom Ck 275kV DCST	0.005	0.045	0.002	-	-	0.052
CP.01958	Larcom Creek 275/132kV Substation (no Aldoga - full breaker and half)	1.220	3.777	0.056	-	-	5.053
CP.01971	Larcom Creek Remote132 kV bus Establishment	0.028	0.086	0.001	-	-	0.115
CP.01976	South Queensland Feeder bays for Energex 1	-	-	-	0.001	0.013	0.014
CP.01977	South Queensland Feeder bays for Energex 2	-	-	-	0.002	0.012	0.014
CP.01979	South Queensland additional 110/33kV transformer for Energex 1	-	-	0.013	0.051	0.001	0.065
CP.01980	South Queensland 110kV bus establishment for Energex 110/11kV substation	-	-	0.021	0.065	0.001	0.087
CP.01981	South Queensland 110/33kV substation establishment for Energex 1	-	-	-	0.017	0.075	0.092
CP.01982	South Queensland 110/33kV substation establishment for Energex 2	-	-	-	0.006	0.026	0.032
CP.01983	Central Queensland Feeder bays for Ergon 1	-	-	0.002	0.013	0.001	0.016
CP.01984	Central Queensland Feeder bays for Ergon 2	-	-	-	-	0.002	0.002
CP.01985	Central Queensland additional 132/33kV transformer for Ergon No.1	-	-	-	0.020	0.055	0.075
CP.01986	Central Queensland additional 132/66kV substation establishment or Ergon 1	-	-	-	-	0.024	0.024
	TOTAL NOMINAL	**10.672**	**26.443**	**33.137**	**36.690**	**31.238**	**138.180**
	TOTAL REAL ($06/07)	**10.370**	**24.969**	**30.405**	**32.713**	**27.064**	**125.521**

APPENDIX C

Projects under construction

Project	Description	Original Revenue Proposal - Active	Supp Revenue Proposal - Active	% Increase	Reasons for Cost Increase
		$Nom	$Nom		
CP.00364	Murarrie 2nd 300MVA275/110kV Transformer	9.434	10.100	7%	Input cost increases and minor change in scope of works (approx 360k).
CP.00383	Ross - Yabulu Easement & Sub Site Acquis	1.673	1.871	12%	Property compensation and associated costs and designation process costs.
CP.00618	Kareeya-Innisfail Line Replace Easmt Acq	5.600	5.600	0%	
CP.00639	NEBO/ROSS EASEMENT ACQUISITION	2.237	3.196	43%	Expected additional cultural heritage, environmental investigation and project management costs.
CP.00704	SPRINGDALE - TARONG EASEMENT ACQUISITION	8.102	9.286	15%	Expected additional environmental management and easement compensation costs.
CP.00736	Greenbank SVC	22.945	32.076	40%	Recent SVC price increases, input cost increases and change to scope.
CP.00752	SVC Secondary Systems Replacement	24.286	24.286	0%	
CP.00861	Innisfail Edmonton Easement Acquisition	1.644	1.644	0%	
CP.01011	Operational WAN Stage 4	0.998	0.998	0%	
CP.01022	Townsville Sth SEC Systems Upgrade	10.481	10.481	0%	
CP.01030	Belmont/Murarrie Easement Acquisition	7.223	9.400	30%	Additional property purchase.
CP.01035	Ross-Townsville South Transmission Reinf	16.519	19.163	16%	Input cost increases.
CP.01037	Barron Gorge 132kV Line Maintenance	8.002	9.282	16%	Input cost increases.
CP.01067	Clare Substation Rebuild	12.886	14.561	13%	
CP.01078	Nudgee 275/110kV Easement Acqusition	7.148	7.148	0%	
CP.01086	Bohle River to Yabulu South Easement Acq	0.546	1.523	na	Error in SAP cost used in original Revenue Proposal. Additional easement acquisition costs.
CP.01087	Bohle River to Townsville GT 132kV Line	18.091	23.400	29%	Increased input costs and change to scope ($0.7m). See more detailed response.
CP.01090	Woree 275kV Reinforcement	17.242	17.242	0%	
CP.01094	Belmont Murarrie Transmission Reinforcem	47.791	47.791	0%	
CP.01100	Middle Ridge - Greenbank Easement Acquis	5.466	6.050	11%	Additional easement and associated costs due to line deviation.
CP.01101	NQ Transmission Reinforcement Stage 2	113.949	132.180	16%	Input cost increases.
CP.01124	Mackay Transmission reinforcement	46.981	46.981	0%	Input cost increases.
CP.01131	Tully-Innisfail 132kV Transmission Line	50.084	63.723	27%	Input cost increases.
CP.01134	South Pine 110kV Substn Refurbishment	33.921	38.331	13%	Input cost increases.
CP.01137	Ross - Yabulu Transmission Reinforcement	36.507	42.300	16%	Input cost increases.
CP.01138	SEQ AUGMENTATION	99.961	115.954	16%	Input cost increases.
CP.01144	Townsville East Substation Establishment	24.220	28.335	17%	Input cost increases.
CP.01177	Belmont 110kV Substation Refurbishment	33.742	33.742	0%	
CP.01186	North Qld Transmission Reinf Stage 1	91.198	105.789	16%	Input cost increases.
CP.01187	Molendinar 275/110kV Transformer Reinf	4.307	7.400	na	Full project cost omitted from Revenue Proposal due to incorrect accounting for insurance spares.
CP.01191	Brisbane South Area Easement Acquisition	0.280	16.416	na	Error in SAP cost used in original Revenue Proposal. Increase in acquisition cost.
CP.01192	Biloela Transformer Augmentation	6.861	7.700	12%	Scope change to reduce outage time required ($0.6m) and additional civil ($0.4m) and connection works.
CP.01198	Wide Bay Transmission Reinforcement	36.029	37.563	4%	
CP.01199	QR Mindi Establishment	12.097	15.000	24%	Input cost increases and change to scope.
CP.01204	Lilyvale - Blackwater 132kV Transm Line	26.537	30.782	16%	Input cost increases.
CP.01221	Ross 132kV Extension(Millchester Bypass)	1.370	1.440	5%	
CP.01237	Barron Gorge Secondary Systems Replace	0.879	0.879	0%	
CP.01243	Bouldercombe to Pandoin 132kV DCST	27.866	32.076	15%	
CP.01245	Mackay-Pioneer Val Transm Line Life Ext	5.594	6.488	16%	Input cost increases.
CP.01246	Mackay-Proserpine Transm Line Life Ext	7.081	8.213	16%	Input cost increases.
CP.01247	Mudgeeraba-Terranora 110kV Line Uprating	0.513	0.595	16%	Input cost increases.
CP.01261	BOWEN 132kV SUBSTATION SITE& EASEMENT AC	2.903	2.903	0%	
CP.01263	Mudgeeraba X-Protection Relay Replacemen	0.204	0.204	0%	
CP.01265	Bowen 132/66kV Substation Establishment	47.065	54.596	16%	Input cost increases.
CP.01266	Abermain 275kV Substation Establishment	21.022	21.022	0%	
CP.01267	MUDGEERABA 110/33kV SUBSTATION ESTABLISH	3.653	4.681	28%	Input cost increase and scope change.
CP.01271	COOROY WEST SUBSTATION SITE & EASEMENT A	6.288	6.863	9%	Full scope showed increase in expected land parcels and higher compensation costs.
CP.01282	Nebo-QR Bolingbroke Easement Acquisition	0.849	0.849	0%	
CP.01285	Bolingbroke QR Rail Supply	17.127	24.024	40%	Increased input costs and additional route length due to environmental and construction accessibility reasons.
CP.01286	Tarong Substation Refurbishment	23.790	23.790	0%	
CP.01294	Strathmore 275kV SVC	38.000	47.350	25%	Recent tender price increase, input cost increases and additional site civil works.
CP.01302	Abermain Substation Site Acquisition	0.194	0.330	70%	Expected increase in land costs.
CP.01313	Ross - Chalumbin OPGW Retrofit	8.330	8.402	1%	
CP.01333	EMS Gen3 Update to Gen4	-	5.930	na	Additional project not included in original Revenue Proposal.
CP.01531	Bundamba 2nd 110/11kV transformer	4.892	6.100	25%	
CP.01559	Edmonton 1st 132kV 30MVAr Capacitor Bank	2.315	2.315	0%	
CP.01837	Palmwoods 350MVAr SVC	32.624	43.669	34%	Expected tender price increases and input cost increases.
CP.96601	Replace Grid DB	-	1.875	na	Error in SAP cost used in original Revenue Proposal.

APPENDIX D

ROAM Consulting update on PNG probability

Appendix D: ROAM Consulting update on PNG probability

ROAM CONSULTING
ENERGY MODELLING EXPERTISE

A.B.N. 54 091 533 621

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30th January 2007

Merryn York
Manager, Revenue Reset Project
Powerlink
33 Harold Street
Virginia
QLD 4014

Powerlink Revenue Reset Proposal – Additional Submission

Dear Merryn,

In July 2005 ROAM Consulting undertook a study of generation development scenarios in support of Powerlink's revenue application for the period 2007/8 – 2011/12. This assignment was updated in February 2006 to incorporate an increased probability of the PNG gas project proceeding. Since that date developments associated with the PNG pipeline have resulted in the likelihood of PNG delivering gas to Queensland in the near term diminishing significantly. In light of this new information Powerlink has requested that ROAM Consulting advise as to the likelihood of the PNG project proceeding within the term of the regulatory period and more generally on the impact on generation development within the Townsville region should the PNG project not proceed.

The PNG Project

Oil search has stated that economically recoverable gas reserves in the PNG highlands measure in the region of 4,800 tcf (trillion cubic feet) this being approximately equal to 4,800 PJ energy equivalent. In order to deliver this gas to markets in Australia AGL formed a consortium with Petronas to build the Australian leg of the proposed PNG pipeline running from Cape York to Gladstone with possible laterals connecting to Mt Isa and the Gove Alumina facility on the Gulf of Carpentaria. In order to underwrite development of the gas field and construction of the PNG gas pipeline the project developers sought to contract approximately 150 – 200 PJ per year for delivery over a twenty to twenty five year period. The largest single customer for PNG gas was to be AGL which had conditionally contracted for 1,500 PJ over twenty years. At an arithmetical average of 75 PJ per year this contract would have met at most 50% of the project's requirements. Additional customers were to have come from a variety of sources including the Gove Alumina facility, Comalco's alumina refining operations at Gladstone and AGL's proposed gas fired power station in Townsville amongst others. In 2006 AGL announced that it was scaling back its development work on the PNG pipeline in what was interpreted as a significant blow to the project and has since stated that whilst it believes that the project will be viable in the longer term this is dependent upon acquiring the necessary level of gas sales. Since making this announcement AGL has moved to obtain control of onshore gas reserves through its acquisition of BHP Billiton's 50% stake in the Moranbah Gas Project and is actively seeking to acquire a stake in the Queensland Gas Company.

Whilst completion of the PNG gas project within the next five years is not impossible ROAM Consulting considers it to be unlikely to proceed within this timeframe. PNG suffers from a number of strategic weaknesses that have hindered its progress to date. Firstly there is the target volume of gas sales that it requires to proceed. PNG requires at least 150 PJ of contracted load per year compared to Queensland's current annual gas consumption of around 100 PJ per year. Whilst PNG gas sales are not limited to the state of Queensland and may also be made to customers in NSW (such as AGL), this statistic nevertheless highlights the magnitude of the task before the PNG developers. A second difficulty is the availability of existing customers. Industrial gas supply agreements are commonly signed on a long term basis ranging up to twenty years and beyond. Whilst this will not be the case for all prospective customers of PNG it nevertheless highlights the difficulty in defining the project's opportunity window. Some potential customers will be locked into existing agreements that do not terminate at dates that are convenient for the project whilst others will be available but cannot wait indefinitely whilst the PNG proponents decide whether or not the project will proceed and to what timing. Offsetting these difficulties is the prospect for new loads to develop encouraged by the availability of large quantities of competitively priced gas. However, the development of Coal Seam Methane in Queensland has proved to be adequate to meet these requirements for a number of projects including the converted Yabulu power station, the Swanbank E power station and prospectively the Spring Gully power station as well. Here CSM can have an advantage in that it may be developed incrementally with exploration and production expanding according to demand so making it capable of responding more flexibly to market requirements. It should also be noted that 2P certified reserves in Queensland stood at 5,064 PJs at the end of 2005 of which 4,209 PJs were from CSM whilst in 1998 the corresponding reserves were 2,841 PJs and 325 PJs respectively. Another difficulty is the increase in costs that the project will have experienced as steel prices have risen over the last several years. Finally there is the issue of timing for the PNG project. Prior to its press announcement AGL had stated the belief that the project could be delivering gas to customers by 2009 although there was considerable speculation within the pipelining industry as to the achievability of this target. Powerlink's next regulatory period covers the years from 2007/8 to 2011/12. The most optimistic view of the project's timing taken before AGL's announcement would have seen the project delivering gas to customers close to half way through that period. Since AGL's announcement the prospective date for completion can only have receded.

In conclusion, given the long standing difficulty that the PNG project has suffered in terms of recruiting sufficient customers, the increasing competition from Coal Seam Methane, increasing costs, the likelihood that the project will recede rather than advance without AGL's commitment and the date of entry having been well into the regulatory period even under the most optimistic assessment of its timing, ROAM Consulting believes that the likelihood of the PNG project supplying gas to Townsville before the end of the next regulatory period is sufficiently remote to warrant a 0% probability in Powerlink's planning process.

Impact of PNG on the Townsville South Generation Project

ROAM Consulting has reviewed the scenario analysis work undertaken previously on behalf of Powerlink with specific regard to the Townsville South project and how this may be affected should PNG not proceed.

Townsville South was originally assessed as proceeding in all scenarios where PNG gas was available and also in all scenarios with high regional demand irrespective of whether PNG went ahead or not. This was the case for both the 80:20 and the 50:50 PNG probability exercises. At present the only field capable of supplying gas to Townsville is the Moranbah Gas Project. As of December 2005 the MGP had 382 PJ of P2 reserves, of which circa 290 PJ were dedicated to Enertrade under its gas supply agreement leaving an available balance of 92 PJ for new projects. For the 400MW CCGT Townsville South project to be bankable it would require circa 20 PJ of gas each year for a term of twenty years. With only 92 PJ available from the MGP the station could be fuelled for less than five years. Approximately 1,500 PJ of 3P reserves are located in the Moranbah region, some of which may be converted to 2P status following further exploration drilling although it is beyond the scope of this report to assess the likely magnitude of any future recertification. Additional 2P reserves would most likely be developed under conditions of increased gas demand in North Queensland. One scenario under which this could occur would be that of high electrical demand throughout the state which would act as a catalyst to all prospective CSM suppliers. ROAM consulting therefore considers that it is appropriate for the Townsville South station to remain as a generation project under those scenarios where demand is at its highest irrespective of whether or not those scenarios also contains the PNG pipeline project. In reaching this conclusion ROAM has also recognised the current inability of any gas field other than the MGP to supply the Townsville region until such time as the North Queensland Gas Pipeline is extended from Moranbah to Gladstone, giving Townsville access to gas from the south of the state. A project to so extend the NQGP is currently under consideration although it is not yet committed. Whilst it is beyond the scope of this report to appraise the prospects of such a pipeline, based on the limited information available ROAM Consulting does not consider that the prospective Moranbah to Gladstone Gas Pipeline at present represents a reliable source of gas into Townsville within the regulatory period.

Regards

Malcolm Whalley
Associate
ROAM Consulting

APPENDIX E

Press release from Oil Research Limited

Appendix E: Press release from Oil Search Limited

OIL SEARCH LIMITED

(Incorporated in Papua New Guinea)
ARBN – 055 079 868

PRESS RELEASE
PNG Gas Commercialisation Update
1 February 2007

The PNG Gas Project participants have recently completed an intensive review of development options for the PNG Gas Project, which commenced when APC withdrew from building the Australian portion of pipeline in mid-2006.

Oil Search and its partners have also fully evaluated a range of other development options for gas at Hides and Kutubu and have identified a number of projects that have demonstrably higher value and return potential than the PNG Gas Project to Australia. These projects include the sale of gas for a Liquefied Natural Gas (LNG) or petrochemical development, which take advantage of a material increase in world gas and oil prices.

In light of the superior returns that may be achieved from these alternative opportunities, the PNG Gas Project participants have agreed to suspend work on the Project and concentrate development of the Hides and Kutubu resource into higher value projects. As such, the agreement that links the Hides and Kutubu fields to underwrite reserves for the Project has not been renewed.

Peter Botten, Oil Search's Managing Director said:

"Oil Search and its partners have dedicated considerable time and effort to fully evaluating the PNG Gas Project. This work included the analysis of a staged development of the PNG Gas Project, with a revised pipeline route through Mt. Isa. The Project participants sought expressions of interest from pipeline builders/owners for construction of the revised configuration and received a positive response. The submissions confirmed Oil Search's belief that the PNG Gas Project is an attractive investment option, based on appropriate cost control and continued strong market support.

Nonetheless, it is clear that the alternative development options, including LNG, petrochemicals and other in-country options, which were not present two years ago, are now demonstrably more attractive and cannot be ignored. The gas prices that can be realised from these projects are not

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constrained by the local market conditions in Eastern Australia, which are dominated by large volumes of competitively priced coal.

Although it is disappointing that activities have ceased on the PNG Gas Project, the alternative development options now represent an opportunity to deliver superior returns, and will add significant medium and long term value and growth potential for both Oil Search and Papua New Guinea".

Mr Botten added:

"Substantial gas resources have been discovered in PNG and an active appraisal/exploration programme is being pursued to prove up more contractable gas. Core gas reserves for development are defined at Hides/Angore and Kutubu, with a range of other fields potentially available for resource support.

ExxonMobil has recently completed initial studies that have demonstrated the attractiveness of an LNG development based on the Hides/Angore fields as the core gas resource. Discussions have been initiated with the Kutubu and Juha field groups to potentially join ExxonMobil and the Hides Joint Venture in this proposed development. Oil Search is supportive of pursuing an LNG development based on the Hides/Angore resource. We believe that there are sufficient reserves at present in the Hides/Angore complex to underwrite a single train LNG development.

The Kutubu Joint Venture is also reviewing a number of commercial options to develop its gas and liquids resource and is well placed in having a range of potentially attractive options in LNG, petrochemicals and straight gas sales to major new resource projects. Kutubu represents a valuable resource and infrastructure hub for any development.

Oil Search and British Gas (BG) have recently completed an initial evaluation of an LNG development, based on the Kutubu resource, backed by one or more of the other gas fields in the Oil Search portfolio. This project would commence with an initial 3-4 mtpa plant (similar in size to others in BG's portfolio) and associated infrastructure, to be optimised based on gas resource and plant efficiency. The objective is to deliver LNG to the market as early as possible, with a target of first deliveries in 2012. Commercial discussions are now taking place with BG to refine the potential project structure and the terms of BG's possible entry.

Oil Search has also been approached by a number of other credible international companies with regard to LNG developments, based on Kutubu and other resources in its portfolio.

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It is recognised that there is considerable value in being a development leader for LNG in PNG and, as a major resource owner, Oil Search is committed to being part of PNG's first LNG development.

In parallel with the LNG development options, Oil Search and the Kutubu Joint Venture are also reviewing supplying gas to a Methanol/DME plant in Port Moresby, led by Mitsubishi Gas Chemical (MGC) and Itochu (ITC). MGC/ITC are finalising their initial feasibility analysis and, subject to closure of gas supply terms, are planning to be in full engineering and design by the end of 2007, with a project investment decision at the end of 2008 and first production in 2011.

Negotiations are also at an advanced stage for the supply of gas to a fertiliser development plant led by Oswal Industries, which is planning to build a world scale plant in Port Moresby with first production planned for 2011.

Other proposals for gas supply have been received from a number of petrochemicals/GTL and industry users. These are being evaluated but are seen to be of lower priority than the LNG, methanol and fertiliser opportunities described above. Evaluation of delivering CNG from Kutubu, or an associated field, to niche markets is also taking place.

Appraisal drilling at the Juha field is now underway and Oil Search sees this resource as being potentially very valuable in backing an LNG development in the medium term. The Company will actively pursue early development of the Juha field, including liquids cycling, if reserve delineation now taking place on the field, is successful.

It is anticipated that Oil Search and the Kutubu Joint Venture will have completed its assessment of the various development alternatives by the middle of 2007, having fully evaluated commercial proposals from project developers and gas buyers.

The Company has a number of attractive choices in commercialising its strategically valuable resource. Based on developing LNG or petrochemicals in PNG, it is important to note that value adding industries and employment opportunities will be concentrated in-country – this represents a significant boost to the PNG economy, over and above the PNG Gas Project, with exports to Australia. It will also allow the Company an opportunity to commercialise gas resources outside the Hides/Kutubu complex, expanding infrastructure and benefits distribution outside these areas, adding value to our total PNG portfolio. Oil Search supports the

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PNG Government's initiatives to facilitate core pipeline infrastructure that will further aid multiple gas development in-country."

PETER BOTTEN
Managing Director
OIL SEARCH LIMITED

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Peter Botten, Oil Search's Managing Director, will be holding a teleconference with analysts and fund manager at 10.30am AEST today, 1 February 2007. The teleconference will be webcast live over Oil Search's website. To listen to the webcast, please log on to www.oilsearch.com. If you have any technical difficulties, please call +61 (0)2 9016 3140.

The webcast will be available in archive form on the Oil Search website 2 -3 hours after the completion of the teleconference.

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APPENDIX F

Regional coincident demand forecasts

Appendix F: Regional coincident demand forecasts

APR 2005 Queensland region (coincident) peak summer demand [MW].

Inclusive of the Tweed area load

	High			Medium			Low		
Summer Forecasts	**10% PoE**	**50% PoE**	**90% PoE**	**10% PoE**	**50% PoE**	**90% PoE**	**10% PoE**	**50% PoE**	**90% PoE**
2006/07	8,971	8,643	8,449	8,499	8,188	8,005	8,123	7,826	7,652
2007/08	9,526	9,180	8,977	8,935	8,612	8,421	8,382	8,079	7,900
2008/09	10,110	9,743	9,527	9,318	8,981	8,782	8,570	8,260	8,078
2009/10	10,761	10,370	10,140	9,674	9,323	9,118	8,755	8,439	8,254
2010/11	11,321	10,910	10,668	10,018	9,656	9,443	8,940	8,617	8,428
2011/12	11,923	11,490	11,235	10,349	9,974	9,754	9,124	8,795	8,602
2012/13	12,506	12,052	11,785	10,690	10,303	10,077	9,298	8,963	8,767
2013/14	13,139	12,661	12,381	11,041	10,641	10,407	9,472	9,131	8,931
2014/15	13,769	13,267	12,974	11,371	10,959	10,718	9,630	9,283	9,080

Source: Table 4.2 from Powerlink's APR 2005.

APR 2006 Queensland region (coincident) peak summer demand [MW].

Inclusive of the Tweed area load

	High			Medium			Low		
Summer Forecasts	**10% PoE**	**50% PoE**	**90% PoE**	**10% PoE**	**50% PoE**	**90% PoE**	**10% PoE**	**50% PoE**	**90% PoE**
2006/07	8,995	8,538	8,221	8,769	8,325	8,016	8,519	8,089	7,791
2007/08	9,565	9,069	8,725	9,190	8,715	8,387	8,835	8,381	8,067
2008/09	10,123	9,591	9,222	9,597	9,097	8,750	9,117	8,645	8,317
2009/10	10,662	10,095	9,702	9,954	9,428	9,065	9,335	8,847	8,509
2010/11	11,700	11,097	10,679	10,290	9,741	9,359	9,531	9,027	8,679
2011/12	12,227	11,589	11,146	10,634	10,059	9,661	9,741	9,222	8,861
2012/13	12,764	12,089	11,621	10,983	10,382	9,967	9,971	9,434	9,062
2013/14	13,328	12,614	12,120	11,342	10,718	10,284	10,181	9,628	9,244
2014/15	13,932	13,177	12,653	11,716	11,064	10,613	10,401	9,832	9,437

Source: Table 3.8 from Powerlink's APR 2006, plus Powerlink advice on Tweed area.

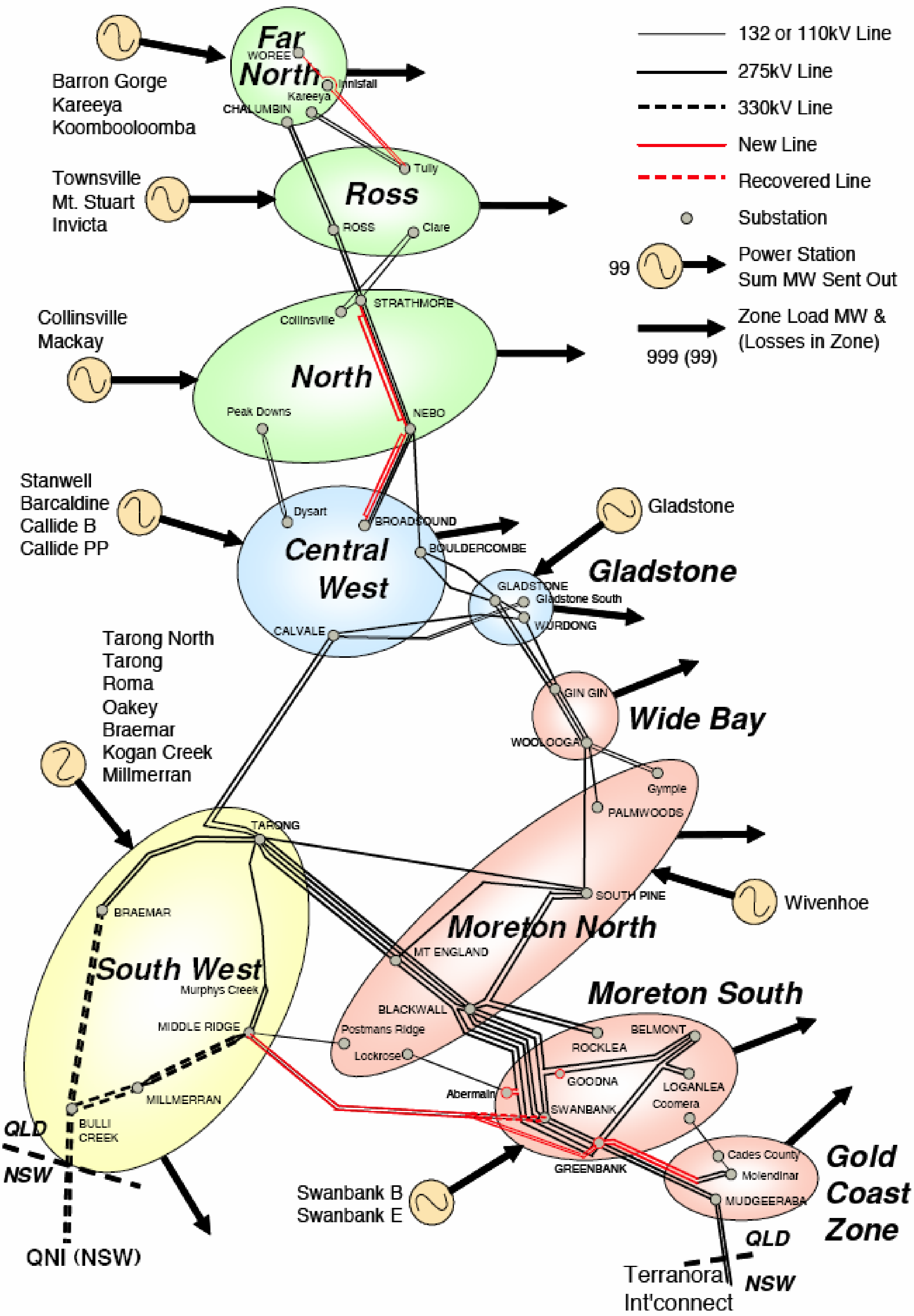
APPENDIX G

Zone definitions and generation and load legend

Appendix G: Zone definitions and generation and load legend

Zone	Area Covered
Far North	North of Tully including Chalumbin.
Ross	North of Proserpine and Collinsville, but excluding the Far North zone (includes Tully).
North	North of Broadsound and Dysart but excluding the Far North and Ross zones (includes Proserpine and Collinsville).
Central West	Collectively encompasses the area south of Nebo, Peak Downs and Mt McLaren, and north of Gin Gin, but excluding that part defined as the Gladstone zone.
Gladstone	Specifically covers the Powerlink transmission network connecting Gladstone power station, Callemondah (railway supply), Gladstone South, QAL supply, Wurdong and Boyne Smelter supply.
Wide Bay	Gin Gin and Woolooga 275kV substation loads excluding Gympie.
South West	Tarong and Middle Ridge load areas west of Postmans Ridge. From winter 2005 onwards, includes Goondiwindi (Waggamba) load.
Moreton North	South of Woolooga and east of Middle Ridge, but excluding the Moreton South and Gold Coast zones.
Moreton South	Generally, south of the Brisbane River, but currently includes the Energex Victoria Park and Mayne 110kV substation load areas as supplied from Belmont 275/110kV substation, and excludes the Gold Coast zone.
Gold Coast	South of Coomera to the Gold Coast and excludes Tweed Shire of NSW.

Source: Powerlink APR 2006, Page 40



Source: Powerlink APR 2006, Page 99

APPENDIX H

Zone based coincident demand forecasts (Medium growth, 50% PoE)

Appendix H: Zone based coincident demand forecasts (Medium Growth, 50% PoE)

APR 2006 (coincident) peak summer demand for the Medium growth scenario and 50% PoE conditions [MW].

Summer Forecasts	Far North	Ross	North	Central West	Glad-stone	Wide Bay	South West	Moreton North	Moreton South	Gold Coast / Tweed	Total
2006/07	321	461	407	583	1,159	251	395	1,615	2,318	816	8,326
2007/08	334	474	421	611	1,196	252	408	1,708	2,442	868	8,714
2008/09	348	485	436	632	1,207	259	422	1,791	2,580	936	9,096
2009/10	362	497	472	653	1,224	266	437	1,883	2,652	983	9,429
2010/11	377	507	483	669	1,243	273	452	1,959	2,739	1,040	9,742
2011/12	392	519	500	684	1,252	280	466	2,037	2,832	1,098	10,060
2012/13	407	530	514	700	1,262	287	480	2,116	2,925	1,161	10,382
2013/14	423	542	529	715	1,271	295	494	2,198	3,024	1,226	10,717
2014/15	440	554	544	731	1,281	302	509	2,294	3,119	1,290	11,064

APR 2005 (coincident) peak summer demand for the Medium growth scenario and 50% PoE conditions [MW].

Summer Forecasts	Far North	Ross	North	Central West	Glad-stone	Wide Bay	South West	Moreton North	Moreton South	Gold Coast / Tweed	Total
2006/07	314	549	362	510	1,252	254	389	1,515	2,241	802	8,188
2007/08	327	562	379	532	1,263	262	404	1,667	2,360	856	8,612
2008/09	341	575	393	546	1,278	269	421	1,765	2,478	915	8,981
2009/10	355	588	409	560	1,286	277	438	1,853	2,589	970	9,325
2010/11	369	601	423	573	1,297	285	455	1,934	2,692	1,026	9,655
2011/12	384	615	439	587	1,307	293	473	2,015	2,782	1,078	9,973
2012/13	400	630	454	601	1,319	301	491	2,116	2,862	1,129	10,303
2013/14	416	644	470	615	1,330	309	510	2,206	2,956	1,185	10,641
2014/15	430	658	485	629	1,335	317	528	2,291	3,048	1,238	10,959

APPENDIX I

Zone based coincident demand forecasts (Medium growth, 10% PoE)

Appendix I: Zone based coincident demand forecasts (Medium Growth, 10% PoE)

APR 2006 (coincident) peak summer demand for the Medium growth scenario and 10% PoE conditions [MW].

Summer Forecasts	Far North	Ross	North	Central West	Glad-stone	Wide Bay	South West	Moreton North	Moreton South	Gold Coast / Tweed	Total
2006/07											
2007/08	346	490	435	632	1,237	260	422	1,827	2,613	929	9,191
2008/09	360	503	452	655	1,250	268	438	1,915	2,759	1000	9,600
2009/10	375	515	489	678	1,269	276	453	2,013	2,836	1051	9,955
2010/11	391	527	502	694	1,291	283	469	2,094	2,928	1111	10,290
2011/12	407	539	520	712	1,302	291	485	2,178	3,028	1174	10,636
2012/13	424	552	535	729	1,313	299	500	2,262	3,128	1,241	10,983
2013/14	441	565	551	746	1,325	307	515	2,351	3,233	1,311	11,345
2014/15	459	578	568	763	1,337	315	531	2,453	3,335	1,380	11,719

APR 2005 (coincident) peak summer demand for the Medium growth scenario and 10% PoE conditions [MW].

Summer Forecasts	Far North	Ross	North	Central West	Glad-stone	Wide Bay	South West	Moreton North	Moreton South	Gold Coast / Tweed	Total
2006/07											
2007/08	337	578	390	548	1,300	269	416	1,741	2,464	893	8,936
2008/09	351	591	404	561	1,315	277	433	1,843	2,587	955	9,317
2009/10	365	605	420	576	1,323	285	451	1,934	2,703	1,013	9,675
2010/11	380	619	435	589	1,333	293	468	2,019	2,810	1,071	10,017
2011/12	395	633	451	603	1,345	301	487	2,104	2,904	1,126	10,349
2012/13	411	647	467	618	1,356	310	505	2,209	2,988	1,179	10,690
2013/14	427	662	484	632	1,367	318	524	2,303	3,086	1,237	11,040
2014/15	442	676	499	646	1,372	326	542	2,393	3,183	1,293	11,372

APPENDIX J

Area based coincident demand forecasts

Appendix J: Area based coincident demand forecasts

Area based non-coincident peak demand - 10%PoE Medium growth forecast changes

		2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
SEQ	**APR 2005**	5097	5385	5650	5900	6134	6376	6626	6889
	APR 2006	5369	5673	5900	6133	6380	6632	6894	7168
	Increase	**272**	**288**	**250**	**233**	**246**	**255**	**268**	**279**
SQ	**APR 2005**	5771	6083	6371	6646	6905	7173	7449	7729
	APR 2006	6029	6355	6603	6860	7128	7402	7686	7982
	Increase	**258**	**272**	**232**	**214**	**223**	**230**	**238**	**253**
GC/TW	**APR 2005**	909	971	1030	1089	1146	1200	1259	1321
	APR 2006	936	1008	1059	1120	1183	1251	1321	1391
	Increase	**27**	**37**	**29**	**31**	**38**	**52**	**62**	**70**
NQ	**APR 2005**	1408	1454	1502	1551	1600	1651	1703	1757
	APR 2006	1471	1516	1587	1628	1676	1722	1770	1819
	Increase	**63**	**62**	**84**	**78**	**75**	**71**	**67**	**62**
FNQ	**APR 2005**	369	385	400	416	433	451	469	487
	APR 2006	375	390	405	422	439	456	474	493
	Increase	**5**	**5**	**5**	**6**	**6**	**6**	**6**	**6**

Area based non-coincident peak demand - 10%PoE High growth forecast changes

		2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
SEQ	**APR 2005**	5485	5899	6360	6763	7152	7561	8004	8478
	APR 2006	5777	6208	6633	7021	7428	7853	8315	8808
	Increase	**292**	**309**	**273**	**257**	**276**	**291**	**311**	**330**
SQ	**APR 2005**	6201	6652	7160	7602	8035	8486	8975	9487
	APR 2006	6420	6872	7312	7849	8273	8721	9203	9717
	Increase	**218**	**220**	**152**	**247**	**239**	**235**	**228**	**230**
GC/TW	**APR 2005**	977	1063	1158	1246	1338	1425	1523	1627
	APR 2006	1006	1103	1190	1281	1382	1487	1598	1714
	Increase	**29**	**40**	**33**	**35**	**44**	**61**	**75**	**86**
NQ	**APR 2005**	1478	1546	1634	1706	1788	1866	1952	2043
	APR 2006	1546	1614	1728	1795	1877	1951	2033	2120
	Increase	**68**	**68**	**95**	**89**	**88**	**85**	**81**	**77**
FNQ	**APR 2005**	383	403	427	448	472	494	519	546
	APR 2006	389	408	432	454	478	500	526	553
	Increase	**6**	**5**	**5**	**6**	**6**	**6**	**6**	**6**

Area based non-coincident peak demand - 10%PoE Low growth forecast changes

		2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
SEQ	**APR 2005**	4778	4937	5089	5236	5370	5504	5640	5782
	APR 2006	5034	5207	5321	5451	5594	5734	5879	6028
	Increase	**255**	**270**	**232**	**215**	**224**	**230**	**239**	**246**
SQ	**APR 2005**	5408	5573	5735	5894	6041	6187	6334	6481
	APR 2006	5706	5903	6035	6182	6341	6504	6666	6831
	Increase	**299**	**330**	**300**	**288**	**300**	**317**	**331**	**350**
GC/TW	**APR 2005**	853	892	929	969	1005	1038	1074	1112
	APR 2006	878	925	956	996	1038	1083	1127	1171
	Increase	**25**	**34**	**26**	**28**	**33**	**45**	**53**	**59**
NQ	**APR 2005**	1333	1349	1375	1400	1432	1460	1486	1518
	APR 2006	1392	1405	1451	1469	1498	1521	1542	1570
	Increase	**59**	**56**	**76**	**69**	**66**	**61**	**56**	**52**
FNQ	**APR 2005**	348	355	364	373	385	395	405	417
	APR 2006	353	360	369	379	390	400	410	422
	Increase	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**

APPENDIX K

CQ-SQ review project timings

Appendix K: CQ-SQ Review project timings

Scen.	**00369** Establish Halys 275kV Substation and Braemar to Halys 500kV DCST operating at 275kV		**00369/A** Establish Halys 275kV Substation and Calvale to Halys 2nd 275kV DCST 1st stage (single circuit strung)		**00369/B** Establish Halys 275kV Substation and Calvale to Halys 2nd 275kV DCST 1st stage (both circuit strung)	
	2005 Forecast	2006 Forecast	2005 Forecast	2006 Forecast	2005 Forecast	2006 Forecast
1						
2		31/10/2013				
3						
4						
5						
6		31/10/2012				
7						
8						
9	31/10/2011	31/10/2011				
10			31/10/2010	31/10/2008		
11			31/10/2011			31/10/2008
12	31/10/2012					31/10/2008
13	31/10/2011	31/10/2011				
14	31/10/2010			31/10/2008		
15	31/10/2013			31/10/2008		
16	31/10/2011			31/10/2008		
17	31/10/2011	31/10/2011				
18	31/10/2011			31/10/2008		
19			31/10/2011			31/10/2008
20				31/10/2008		
21	31/10/2012	31/10/2011				
22	31/10/2011			31/10/2008		
23	31/10/2013			31/10/2008		
24				31/10/2008		
25	31/10/2011	31/10/2010				
26	31/10/2012					31/10/2008
27					31/10/2009	31/10/2008
28					31/10/2009	31/10/2008
29	31/10/2011	31/10/2010				
30	31/10/2011			31/10/2008		
31				31/10/2008		
32				31/10/2008		
33	31/10/2009			31/10/2008		
34	31/10/2009			31/10/2009		
35	31/10/2009	31/10/2009				
36	31/10/2009			31/10/2009		
37	31/10/2009	31/10/2009				
38	31/10/2009			31/10/2009		
39	31/10/2009	31/10/2009				
40	31/10/2009	31/10/2009				
	23	12	3	16	2	6

APPENDIX L

Annual estimated forecast capex adjustments – Median commissioning dates

Appendix L: Annual estimated forecast capex adjustments – Median commissioning dates

	Median Commissioning date	2006 Load Forecast	$000's nominal 2006-07	2007-08	2008-09	2009-10	2010-11	2011-12	Probability %	$000's (06/07) 2007-08	2008-09	2009-10	2010-11	2011-12	Probability Weighted Total Reg. Period
CP.00369	31/10/2011	Establish Halys 275kV Substation and Braemar to Halys 500kV DCST operating at 275kV				16,219	166,614	8,229	65.67			14,881	148,553	7,129	112,010
CP.00775/B	31/10/2011	Braemar to Halys 500kV DCST line operating at 275kV (Halys already established)				12,981	133,313	6,582	13.28			11,911	118,862	5,703	18,123
CP.00369/A	31/10/2008	Establish Halys 275kV Substation and Calvale to Halys 2nd 275kV DCST 1st stage (single circuit strung)	20,279	208,470	10,296				12.53	202,575	9,722				26,605
CP.00369/B	31/10/2008	Establish Halys 275kV Substation and Calvale to Halys 2nd 275kV DCST 1st stage (both circuit strung)	23,489	241,222	11,902				0.75	234,401	11,238				1,837
CP.01512/A	31/10/2009	Strathmore-Ross 275kV DCST - both circuits strung (paralleled operation)		13,081	134,306	6,629			47.21	12,711	126,818	6,083			68,739
CP.01540	31/07/2011	Middle Ridge 1st Transformer upgrade to 1500MVA				1,945	5,450	38	27.35			1,785	4,859	33	1,826
CP.01544	31/07/2011	Southpine 350MVAr SVC				18,845	9,146		29.34			17,291	8,155		7,465
CP.01615	30/06/2009	Auburn River Switching Station (2 switched circuits)		5,409	14,671				22.79	5,256	13,853				4,355
CP.01615/D	31/07/2010	Auburn River Switching Station (3 switched circuits)			3,704	11,428	171		2.80		3,497	10,485	153		396
CP.01615/C	31/08/2012	Auburn River Switching Station (4 switched circuits)					7,886	27,624	0.00				7,031	23,933	
CP.01836	31/08/2009	Gin Gin 250MVAr SVC		17,686	10,959				16.44	17,186	10,348				4,526
CP.01841	31/07/2011	Millmerran Series Line Reactors				977	3,000	45	27.35			897	2,675	39	987
CP.01875	31/10/2011	Halys to Blackwall 500kV operating at 275kV				19,623	201,416	9,939	68.97			18,005	179,582	8,611	142,211
CP.01877/B	31/10/2011	Halys to Blackwall 500kV operating at 500kV				32,667	146,283	23,699	1.01			29,974	130,425	20,533	1,829
CP.01959	31/10/2011	Braemar to Halys operating at 500kV				10,663	109,588	5,415	1.01			9,783	97,709	4,691	1,134
CP.01833/A	30/10/2008	Easement Acquisition for Calvale to Halys 2nd 275kV Double Circuit Line (TE)	1,878	1,811	335				12.67	1,760	317				263
CP.01833/B	30/10/2009	Easement Acquisition for Calvale to Halys 2nd 275kV Double Circuit Line (compensation)		129	2,942	143			12.67	125	2,778	131			384

CP.01722/B		Calvale to Halys 2nd 275kV DCST 1st stage (single circuit strung - Halys established)							0.00						
CP.01156/B	31/08/2012	Stanwell to Broadsound 2nd 275 Circuit						17,520	40.94					15,179	6,214
CP.01792	30/09/2012	Karana Double Tee from Upper Kedron					228	1,322	76.07				203	1,145	1,026
CP.01594	30/09/2013	Abermain 2nd 275/110kV 300MVA Transformer						2,605	76.07					2,257	1,717
CP.01839	31/08/2012	Cedar Creek 275/110kV Substation Establishment					6,460	22,652	7.28				5,760	19,626	1,848
CP.01595	31/10/2011	Goodna 2nd 275/110kV 375MVA Transformer				2,576	10,122	425	7.28			2,363	9,025	368	856
CP.01195/A	31/10/2009	Larapinta 275kV Substation Establishment		10,169	45,398	7,332			100.00	9,881	42,867	6,728			59,476
CP.01528/A	31/03/2010	Molendinar 3rd 275/110kV 300MVA transformer		3,133	16,541	940			100.00	3,045	15,619	863			19,526
CP.00390	30/09/2012	Rocklea 275kV bus & 3rd 300MVA 275/110kV transformer					4,984	18,657	76.07				4,443	16,164	15,677
CP.01844	31/08/2008	Southpine Transformer Augmentation and 110kV Split Bus	3,966	13,958	487				100.00	13,563	460				14,023
CP.01684	31/07/2010	Swanbank A 2nd 275/110kV Transformer Connection			620	1,748	12		100.00		586	1,604	11		2,200
		Total weighted capex over the Reg. Period for these Projects based on the MEDIAN date													**515,255**

			$000's nominal							$000's (06/07)					
	Median Commissioning date	**2005 Load Forecast**	**2006-07**	**2007-08**	**2008-09**	**2009-10**	**2010-11**	**2011-12**	**Proba-bility %**	**2007-08**	**2008-09**	**2009-10**	**2010-11**	**2011-12**	**Probability Weighted Total Reg. Period**
CP.00369	31/10/2011	Establish Halys 275kV Substation and Braemar to Halys 500kV DCST operating at 275kV				16,219	166,614	8,229	73.27			14,881	148,553	7,129	124,968
CP.00775/B	31/10/2011	Braemar to Halys 500kV DCST line operating at 275kV (Halys already established)				12,981	133,313	6,582	2.80			11,911	118,862	5,703	3,827
CP.00369/A	31/10/2011	Establish Halys 275kV Substation and Calvale to Halys 2nd 275kV DCST 1st stage (single circuit strung)				22,716	233,462	11,535	2.80			20,843	208,154	9,994	6,702
CP.00369/B	31/10/2009	Establish Halys 275kV Substation and Calvale to Halys 2nd 275kV DCST 1st stage (both circuit strung)		24,378	250,220	12,347			0.00	23,688	236,269	11,329			
CP.01512/A	31/10/2010	Strathmore-Ross 275kV DCST - both circuits strung (paralleled operation)			13,573	139,374	6,881		47.21	0	12,816	127,882	6,135		69,315

CP.01540	31/07/2010	Middle Ridge 1st Transformer upgrade to 1500MVA		1,887	5,287	37		24.48		1,781	4,851	33		1,631
CP.01544	31/07/2012	Southpine 350MVAr SVC				19,510	9,470	69.34				17,395	8,205	17,751
CP.01615	31/10/2009	Auburn River Switching Station (2 switched circuits)	3,271	14,611	2,361			5.23	3,179	13,797	2,166			1,002
CP.01615/D	31/10/2010	Auburn River Switching Station (3 switched circuits)		2,491	11,118	1,795		0.75		2,352	10,201	1,601		106
CP.01615/C		Auburn River Switching Station (4 switched circuits)						0.00						
CP.01836	31/10/2009	Gin Gin 250MVAr SVC	10,642	18,250				2.09	10,341	17,232				575
CP.01841	31/07/2010	Millmerran Series Line Reactors		1,626	5,155	238		24.48		1,535	4,730	213		1,586
CP.01875	31/10/2012	Halys to Blackwall 500kV operating at 275kV				20,355	208,953	29.52				18,148	181,035	58,807
CP.01833/A	30/10/2009	Easement Acquisition for Calvale to Halys 2nd 275kV Double Circuit Line (TE)	2,140	2,179	426			3.55	2,080	2,058	391			161
CP.01833/B	30/10/2010	Easement Acquisition for Calvale to Halys 2nd 275kV Double Circuit Line (compensation)		161	3,982	209		3.55		152	3,653	186		142
CP.01722/B	31/10/2010	Calvale to Halys 2nd 275kV DCST 1st stage (single circuit strung)		17,186	170,056	8,089		0.61		16,227	156,034	7,212		1,089
CP.01792	30/09/2013	Karana Double Tee from Upper Kedron					236	76.07					205	156
CP.01594	30/09/2011	Abermain 2nd 275/110kV 300MVA Transformer			2,405	9,011	59	7.28			2,207	8,034	51	749
CP.01839	31/08/2013	Cedar Creek 275/110kV Substation Establishment					6,709	7.28					5,813	423
CP.01595	31/10/2013	Goodna 2nd 275/110kV 375MVA Transformer					2,789	7.28					2,416	176
CP.01195/A	31/10/2010	Larapinta 275kV Substation Establishment		10,540	47,060	7,602		100.00		9,952	43,180	6,778		59,910
CP.01528/A	31/03/2010	Molendinar 3rd 275/110kV 300MVA transformer	3,133	16,541	940			100.00	3,045	15,619	863			19,526
CP.00390	30/09/2013	Rocklea 275kV bus & 3rd 300MVA 275/110kV transformer					5,182	76.07					4,490	3,415
CP.01844	31/08/2009	Southpine Transformer Augmentation and 110kV Split Bus	4,134	14,536	508			100.00	4,017	13,726	466			18,209
CP.01684	31/07/2012	Swanbank A 2nd 275/110kV Transformer Connection				667	1,879	76.07				594	1,628	1,690
		Total weighted capex over the Reg. Period for these Projects based on the MEDIAN date												**391,915**